Q. **Other**

Further to CA-NLH-097, that reply provides reports of the Board's financial consultants for 2009, 2010 and 2011. Please provide copies of any further reports that are available.

A. Please refer to CA-NLH-324 Attachment 1. The 2013 Annual Financial Review of Newfoundland and Labrador Hydro is not yet available.

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Board of Commissioners of Public Utilities 2012 Annual Financial Review of Newfoundland and Labrador Hydro

Contents

Executive Summary

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings and recommendations with respect to our 2012 annual financial review of Newfoundland and Labrador Hydro ("the Company") ("Hydro"). Below is a summary of the key observations and findings included in our report.

Our review identified several changes made to the code of accounts in 2012 including the creation of additional accounts to record Accumulated Other Comprehensive Income ("AOCI"), rebates due to the Innu Communities under the terms of the Upper Churchill Redress agreement, contributions in aid of construction in accordance with newly adopted regulatory standards, as well as other accounts related to the adoption of new regulatory standards. While numerous accounts were added to the system for 2012, these changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

The return on average rate base calculated by the Company on Return 12 was 7.00%. We noted that included in the 2012 average rate base are 2012 capital asset purchases of $234,000 relating to the upgrade of the Cat Arm access road which cannot be added to rate base without the approval of the Board. The impact on the 2012 average rate base is a decrease of $117,000 and had a negligible impact on the rate of return on rate base for 2012. We also noted that included in the 2012 average rate base are expenditures of $1,374,000 relating to the Black Tickle Diesel Fire Restoration Project which have not been approved by the Board. The impact on the 2012 average rate base is a decrease of $687,000 and an increase on the rate of return on rate base of 1 bps to 7.01%.

We reviewed the controls that the Company put in place over the preparation of the rate base computation in 2012 as a result of errors and omissions that were identified in previously filed calculations of average rate base. We noted that the controls and procedures put in place were designed effectively and included formal documentation that these controls were performed.

The Company's calculation of return on regulated average equity for 2012 on Return 13 was 5.25% compared with a return of 6.59% in 2011. The decrease from prior year is primarily due to net profit from regulated operations of approximately $16.9 million, a decrease of $3.7 million over 2011.

The Company's interest coverage for 2012 was calculated at 1.33 compared to 1.60 for 2011. The calculation of interest coverage includes both regulated and non-regulated operations. The decrease in interest coverage is primarily due to a decrease in income from operations in 2012 of $29.2 million compared to 2011.

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 showing a ratio of 81.4:18.6. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. The Company's target capital structure comprised of 75% debt and 25% common equity for regulated operations. The actual 2012 ratio was approximately 71% debt (excluding employee benefits and asset retirement obligation) and 29% equity. No regulated dividends were paid on March 31, 2013 and March 31, 2012 to maintain this target ratio.

The net impact on regulated earnings for 2012 was a decrease over 2011 of $3.7 million. This decrease was primarily attributable to an increase in depreciation of $1.9 million, an increase in power purchased of $4.8 million, an increase in salaries and fringe benefits of $3.4 million, an increase in professional services of $1.2 million, and an increase in the loss on disposal of $4.5 million. The impact of this increase in expenses was partially offset by an increase in revenue of $9.2 million and an increase in cost recoveries of $2.7 million

We reviewed Hydro's rates of depreciation to assess their compliance with the 2012 Gannett Fleming Depreciation Study relating to plant in service as of December 31, 2009. No discrepancies were noted from our review nor has any information come to our attention to indicate that the amount reported as depreciation is not in accordance with Board Orders.

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services. Additionally, we prepared a separate report on Hydro's intercompany transactions over the period 2008-2010 between the regulated business units within Hydro and the other Nalcor entities and lines of business. This report was completed in July 2012.

The Rate Stabilization Plan ("RSP") ("the Plan") had an accumulated credit balance of approximately $201.7 million at December 31, 2012, which comprises balances of $64.9 million due to the utility customer, $104.1 million due to industrial customers and $32.7 million in the hydraulic variation account. Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2012 are supported by Hydro's documentation and are accurately calculated.

Our analysis of the Company's deferred charges indicated that all were in accordance with applicable Board Orders. Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2012 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2009, 2010, 2011, and 2012. In all years the Company spent significantly less than expected and we recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the budgeting process and lack of participation in the Conservation Demand Program.

We have reviewed the Key Performance Indicator ("KPI") results and the explanations provided by Hydro for the changes and variations experienced in 2012 and find them to be consistent with our observations and findings noted during our annual financial review.

The Company was under budget by 17.68% on its capital expenditures in 2012 compared to an under budget variance of 6.43% in 2011. During our review of Hydro's 2012 capital expenditures we noted exceptions relating to the Company's reporting requirements as follows: it did not comply with guideline 1900.6 in relation to filing a report with the Board for its intent to proceed with an expenditure greater than $50,000 without the approval of the Board using the Allowance for Unforeseen Items account; also it remains uncertain whether the work relating to the 'Black Tickle Diesel Fire Restoration Project' was an appropriate use of the 'Allowance for Unforeseen Events' account.

Introduction

This report to the Board of Commissioners of Public Utilities ("the Board") presents our observations, findings, and recommendations with respect to our 2012 Annual Financial Review of Newfoundland and Labrador Hydro.

Scope and Limitations

Our review was carried out in accordance with the following Terms of Reference:

1. Examine Hydro's accounting system and code of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.

2. Review the calculations of the return on rate base, return on equity, capital structure and interest coverage ratio.

3. Conduct an examination of operations and administration expenses, fuels, power purchased, depreciation, and interest to assess their reasonableness and prudence in relation to sales of power and energy. The examination of the foregoing will include, but is not limited to, the following:

    a) amortization of deferred charges,
    b) salaries and benefits,
    c) system equipment maintenance,
    d) insurance (including director's liability),
    e) transportation,
    f) building rental and maintenance,
    g) professional services,
    h) miscellaneous,
    i) capitalized expenses,
    j) intercompany charges,
    k) membership fees,
    l) fuels,
    m) power purchased,
    n) depreciation,
    o) interest,
    p) office supplies and expenses, and
    q) bad debts.

4. Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings. This will include a review of how costs are allocated between the regulated and non-regulated operations including a review of labour costing relating to its billing rates for Hydro and its related companies.

5. Review Hydro's rates of depreciation and assess their compliance with the depreciation methodology approved in P.U. 40 (2012). Assess reasonableness of depreciation expense.

6. Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board directives.

7. Conduct an examination of the changes to deferred charges and assess their appropriateness in relation to sales of power and energy.

8. Review Minutes of Board of Directors and Management Committee meetings.

9. Review Hydro's annual report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2012.

10. Examine the Company's 2012 capital expenditures in comparison to budgets and prior years. Included in this review will be an analysis of amounts included in 'Allowance for Unforeseen Items'.

The nature and extent of the procedures which we performed in our review varied for each of the items in the Terms of Reference. In general, our procedures were comprised of:

- inquiry and analytical procedures with respect to financial information provided by Hydro;
- examining, on a test basis where appropriate, documentation supporting amounts included in Hydro's records; and,
- assessing Hydro's compliance with Board directives.

The procedures undertaken in the course of our financial review do not constitute an audit of Hydro's financial information and consequently, we do not express an opinion on the financial information as provided by Hydro.

The financial statements of the Company for the year ended December 31, 2012 have been audited by Deloitte & Touché LLP, Chartered Accountants, who have expressed their opinion on the fairness of the statements in their report dated April 23, 2013. In the course of completing our procedures we have, in certain circumstances, referred to the audited financial statements and the historical financial information contained therein.

Accounting System and Code of Accounts

Scope: ***Examine Hydro's accounting system and code of accounts to ensure that it can provide information sufficient to meet the reporting requirements of the Board.***

Section 58 of the *Public Utilities Act* states that the Board may prescribe the form of all books, accounts, papers, and records to be kept by Hydro and that Hydro shall comply with all such directions of the Board.

The objective of our review of Hydro's accounting system and code of accounts was to ensure that it can provide information sufficient to meet the reporting requirements of the Board. We have observed that the Company has in place a well-structured, comprehensive system of accounts and organization / reporting structure. The system allows for adequate flexibility to allow the Company to meet its own as well as the Board's reporting requirements. Our review indicated several changes made to the code of accounts in 2012 including the creation of additional accounts to record Accumulated Other Comprehensive Income ("AOCI"), rebates due to the Innu Communities under the terms of the Upper Churchill Redress agreement, contributions in aid of construction in accordance with newly adopted regulatory standards, as well as other accounts related to the adoption of new regulatory standards. While numerous accounts were added to the system for 2012, these changes are not significant and the Company believes it will enhance its ability to provide sufficient information to meet the reporting requirements of the Board.

Return on Rate Base and Equity, Interest Coverage and Capital Structure

Scope: ***Review the calculation of the return on rate base, return on equity, capital structure and interest coverage ratio.***

Return on Rate Base

The Company's calculation of average rate base is included on Return 3 and the calculation of return on average rate base is included on Return 12 of the annual report to the Board. The return on average rate base for 2012 was 7.00% (2011 – 7.46%).

Our procedures with respect to verifying the reported average rate base and return on average rate base included:

- agreeing all carry-forward and component data to supporting documentation;
- checking clerical accuracy of the continuity of the rate base and the return on average rate base; and
- reviewing the methodology used in determining average rate base and return on average rate base to ensure it is in accordance with Board Orders.

Details with respect to Hydro's calculation of average rate base and return on average rate base are as follows:

(000)'s	2012	2011	2010 (Note 1)
Plant investment (Note 2)	$ 1,510,595	$ 2,191,991	$ 2,136,058
Less: Accumulated depreciation (Note 2)	(88,865)	(707,241)	(669,742)
CIAC's (Note 2)	(14,052)	(98,054)	(97,257)
Asset retirement obligations	(22,878)	(19,126)	(11,395)
Asset retirement obligations - accumulated depreciation	3,193	1,149	-
Holyrood fuel oil heat tracing	(783)	-	-
Holyrood fuel oil heat tracing - accumulated depreciation	8	-	-
	1,387,218	1,368,719	1,357,664
Balance previous year	1,368,719	1,357,664	1,353,625
Average	1,377,969	1,363,192	1,355,645
Cash working capital allowance	7,805	4,626	3,093
Fuel inventory	50,308	33,680	29,908
Supplies inventoy	25,339	24,096	24,089
Average deferred charges	65,670	68,047	71,924
Average net assets not in service	(1,040)	(423)	
Average rate base	**$ 1,526,051**	**$ 1,493,218**	**$ 1,484,659**
Regulated net income	$ 16,900	$ 20,599	$ 6,604
Hydro net interest expense	89,960	90,844	86,766
Return on Rate Base	$ 106,860	$ 111,443	$ 93,370
Regulated rate of return on rate base	**7.00%**	**7.46%**	**6.29%**

Note 1: Certain of the 2010 comparative figures have been reclassified to conform with the 2011 and 2012 presentation.

Note 2: In PU 13 (2012), the Board approved the use of the carrying value of Hydro's property, plant and equipment as deemed cost at January 1, 2011. As a result, the 2012 balances of plant investment, accumulated depreciation and CIAC's reflect adjustments to deemed cost at January 1, 2011.

The regulated net income component of the return on rate base excludes all non-regulated earnings and expenses of Hydro. In P.U. 8 (2007) the Board approved an allowed Rate of Return on Rate Base of 7.44% with a range of return of 30 basis points (± 15 basis points). The reported return of 7.00% is below the lower end of the approved range by 29 basis points.

From our review of the return on rate base calculation we note the following:

2012

- In P.U. 5 (2012) the Board approved the capital expenditures relating to the project 'To Replace the Fuel Oil Heat Tracing system at the Holyrood Thermal Generating Station'. The Board has ordered that recovery of this project's associated costs will not be allowed at this time. The order required Hydro to separate and record these costs in an account, the disposition of which will be considered by the Board should Hydro to make subsequent application for recovery of some or all of the associated costs. In accordance with this order, Hydro has excluded capital cost additions of $783,000 from its rate base calculation in relation to Holyrood fuel oil heat tracing costs.

- In P.U. 24 (2012) the Board approved capital expenditures for the upgrade of the Cat Arm access road. This project was completed in 2012 with capital expenditures of $234,000 and the expenditures were included in rate base. The order required Hydro to provide a status report on the application for a Crown Easement no later than its filing of the 2012 Capital Expenditure Report and also ordered that Hydro shall not include the expenditures in its rate base until the Board has confirmed in writing that to do so would be consistent with generally accepted sound public utility practice. On February 28, 2013 Hydro provided a status report on the Crown Easement application stating that Hydro was still awaiting its easement. Currently there is no Board approval of the inclusion of the cost in rate base. The impact on the 2012 average rate base is a decrease of $117,000 to $1,525,934,000 and the adjustment had a negligible impact on the rate of return on rate base for 2012.

- In 2012 the Company recorded an asset retirement obligation of $22,878,000 which is associated with the Holyrood Thermal Generating Station - $20,772,000 and the disposal of Polychlorinated Biphenlys - $2,106,000. The Company has also recorded accumulated amortization of $3,193,000 associated with these asset retirement obligations. The Company has included this obligation in the cost of property, plant, and equipment but has excluded the amount from rate base. In P.U. 29 (2012) the Board ordered that Hydro shall appropriately recognize and record asset retirement obligations in accordance with IFRS and stated that regulatory treatment of the particular asset retirement obligations included in the application will be appropriately considered in the context of a general rate application. Had this amount been included in rate base, average rate base would have increased by $18,831,000 to $1,544,882,000 and the return on average rate base would have decreased to 6.92%.

- In 2012 the Company used $1,374,000 of the 'Allowance for Unforeseen Items' account to cover the cost of capital expenditures relating to the Black Tickle Diesel Fire Restoration Project as discussed in the Capital Expenditure section of this report. Had this amount not been included in rate base, average rate base would have decreased by $687,000 and the rate of return on rate base would have increased by 1 bps to 7.01%. Currently, the Board has not made a final decision on the 2012 average rate base and it remains uncertain if these costs can be included in the 2012 rate base.

2011

- In 2011 the Company included in capital assets $2,001,920 of capital asset purchases which the Board disallowed. Had this amount not been included in rate base, average rate base would have decreased by $1,000,960 and the rate of return on rate base would have increased by 1 bps to 7.47%. Currently, the Board has not made a final decision on the 2011 average rate base and it remains uncertain if these costs can be included in the 2011 and 2012 rate base.

In P.U. 42 (2009) the Board ordered Hydro to file a report no later than March 31, 2010 addressing the implementation of any changes made to its internal audit measures to reduce the possibility of future errors and omissions in the calculation of rate base. This report was filed on March 31, 2010. We reviewed the report, and have the following comments with regards to the internal controls implemented by Hydro in the process of completing the Annual Return and rate base computation:

Internal Control	Comments
Ensuring all carry-forward balances agree with those of prior periods and performing variance analysis of significant changes, to assist in identifying any anomalies in the amounts reported.	We obtained and reviewed Hydro's variance analysis. This analysis provided a reconciliation of each return to Hydro's audited financial statements.
Explicitly cross-referencing all applicable rate base amounts to the relevant sections of the Annual Return and to the external audited financial statements and notes.	For the 2012 Annual Returns, we noted that Hydro included cross-referencing to relevant sections of the annual returns, Board Orders, and/or external audited financial statements, as appropriate for all applicable rate base amounts.
Incorporating a formal review of all Board Orders issued during the reporting period for any directives that have the potential to impact the rate base computation, particularly those that deal with potential deferred charges, to ensure the rate base accurately reflects Board Orders.	Based on discussions with Hydro's officials and review of Hydro's Annual Returns working paper file, a formal review was conducted of all Board Orders issued in 2012.
Performing a formal review of the file prepared in support of the Annual Return, including rate base computations, by professional and knowledgeable accounting staff that are independent of preparation of those documents.	Based on discussions with Hydro's officials and review of Hydro's Annual Returns working paper file, the file was prepared by the *Assistant Divisional Controller* and reviewed by the *Divisional Controller* and the *Corporate Controller* of Hydro. Reviewers were independent of preparation of the file and are professional, qualified accountants. Documentation of the reviewer's sign offs and review were included in the working paper file.

We note that the above procedures constitute sufficient controls over the preparation of the rate base computation and included formal documentation that these controls were carried out.

As a result of completing our procedures we note the following discrepancies on the calculation of average rate base and the rate of return on average rate base included in the Company's annual report to the Board:

2012

- **Included in the 2012 average rate base are 2012 capital asset purchases of $234,000 relating to the upgrade of the Cat Arm access road which has not been approved by the Board.**
- **Included in the 2012 average rate base are expenditures of $1,374,000 relating to the Black Tickle Diesel Fire Restoration Project which have not been approved by the Board.**

2011

- **Included in the 2011 and 2012 average rate base are 2011 capital asset purchases of $2,001,920 which has not been approved by the Board.**

Return on Equity

The Company's calculation of regulated average equity and rate of return on regulated average equity for the year ended December 31, 2012 is included in Return 13 of the annual report to the Board.

Similar to the approach used to verify the rate base and return on average rate base, our procedures in this area focused on verification of the data incorporated in the calculations and on the methodology used by the Company. Specifically, the procedures which we performed included the following:

- agreed all carry-forward data to supporting documentation, including audited financial statements and internal accounting records where applicable;
- agreed component data (dividends, regulated earnings, etc.) to supporting documentation;
- checked the clerical accuracy of the continuity of regulated common equity; and
- recalculated the rate of return on common equity for 2012 and ensured it was in accordance with established regulatory practice.

The return on regulated average equity for 2012 has been calculated by the Company at 5.25%. The Return on Equity is calculated as follows:

(000)'s	**2012**	**2011**	**2010**
Shareholder's equity			
2012	$ 331,174		
2011	$ 312,095	$ 312,095	
2010		$ 312,647	$ 312,647
2009			$ 336,943
Average equity	$ 321,635	$ 312,371	$ 324,795
Regulated earnings	$ 16,900	$ 20,599	$ 6,604
Return on equity	**5.25%**	**6.59%**	**2.03%**

During 2012 Hydro experienced a net profit from regulated operations of approximately $16.9 million, a decrease of $3.7 million over 2011. This is the primary reason for the decrease in the return on equity to 5.25% for 2012 compared to 6.59% in 2011. The decrease in regulated earnings from prior year is due to the following:

	Increase (decrease) in net income (in million's)
Increase in revenue	9.2
Increase in amortization expense	(1.9)
Decrease in interest expense	0.9
Increase in operations expense	(1.9)
Increase in fuel expense	(0.7)
Increase in power purchased expense	(4.8)
Increase in loss on disposal of capital assets	(4.5)
	(3.7)

The "regulated" shareholder's equity of Hydro excludes the portion of equity attributable to non-regulated operations. The adjustments for non-regulated operations are as follows:

(000's)	**2012**	**2011**	**2010**
Equity per non-consolidated financial statements	$ 784,284	$ 751,751	$ 722,162
Less: Contibuted capital - Lower Churchill Development	(15,400)	(15,400)	(15,404)
Share capital issued to finance investment in CF(L)Co.	(22,504)	(22,504)	(22,500)
Accumulated other comprehensive income	(41,628)	(45,106)	(26,783)
Net retained earnings attributable to IOCC	(11,975)	(9,315)	(7,030)
Non-regulated expenses	23,795	23,148	21,694
Net retained earnings attributable to CF(L)Co. (income recorded minus dividends flowed through to government)	(394,755)	(376,503)	(361,613)
Net retained earnings attributable to the sale of recall power (income recorded minus allocation of dividends)	9,357	6,024	2,121
Regulated Equity	**$ 331,174**	**$ 312,095**	**$ 312,647**

The calculation in the above table is consistent with the calculation of regulated equity prepared by the Company in Return 13 of the annual report filed with the Board. The adjustments for non-regulated operations are consistent with prior years.

As a result of completing our procedures, we did not note any discrepancies in the calculation of regulated average equity and rate of return on regulated average equity.

Interest Coverage

Interest coverage for 2012 has been calculated at 1.33 times as follows (includes non-regulated operations):

(000's)	2012	2011	2010
Interest on long-term debt	$ 90,500	90,500	90,500
Accretion, long-term debt	500	500	400
Amortization of FX Loss	2,100	2,100	2,100
RSP interest expense	13,200	12,200	10,200
Other	4,600	4,600	1,400
Gross interest and finance charges	110,900	109,900	104,600
Less: Interest during construction	(2,700)	(1,500)	(1,200)
Interest and finance charges	$ 108,200	108,400	103,400
Income from operations	$ 35,900	64,900	56,900
Interest and finance charges	$ 108,200	108,400	103,400
Adjusted income	$ 144,100	173,300	160,300
Interest Coverage	**1.33**	**1.60**	**1.55**

Interest coverage has decreased compared to 2011. The largest variance is with respect to income from operations, which has decreased by $29,000,000 compared to 2011. In 2012 there was a decrease in non-regulated operating income of $25,300,000 compared to 2011.

Cost of debt was calculated on Return 15 at 8.41% in 2012 compared to 8.49% in 2011. In our review of Return 15 we noted that total regulated debt was overstated by $125,000 however the impact on the cost of debt is negligible.

Capital Structure

The capital structure of Hydro based on its regulated operations is as follows:

(000)'s	2012	%	2011	%	2010	%
Debt	$ 957,000	70.9%	$ 933,000	71.8%	$ 957,000	72.6%
Employee benefits	57,000	4.2%	53,000	4.1%	48,000	3.6%
Asset retirement obligation	5,000	0.3%	2,000	0.1%	-	0.0%
Equity	331,000	24.5%	312,000	24.0%	313,000	23.8%
	$ 1,350,000		$ 1,300,000		$ 1,318,000	

Consistent with the Company's calculation of return on equity, equity included in the capital structure shown above excludes Accumulated Other Comprehensive Income ("AOCI") of $41.6 million (2011 - $45.1 million).

Prior to 2009, Hydro's debt to equity ratio had been trending towards the 80:20 target ratio with 2008 showing a ratio of 81.4:18.6. In 2009, Nalcor provided a $100 million equity injection of contributed capital resulting in a significant reduction in leverage to a ratio of 72.0:28.0. Currently, the Company's target corporate capital structure comprised of 75% debt and 25% common equity for regulated operations. In order to maintain this target ratio the Company implemented the following dividend policy:

"*Corporation annually on or before March 31 of each year, pay a dividend on its common shares if the percentage of debt to debt plus equity in the capital structure of the corporation on a regulated basis at the end of the immediately preceding fiscal year was less than 75% and that the amount of the dividend in that case will be equal to the amount that would be necessary to bring the percentage of debt to debt plus equity up to 75% at December 31st of the immediately preceding year, as if the dividend in question had been on that date.*"

The actual 2012 ratio was approximately 71% (2011 – 72%) debt (excluding employee benefits and asset retirement obligation) and 29% (2011 – 28%) equity reported in Return 14. According to Hydro, the corporate regulated capital structure used in the calculation of the regulated dividend is based on a rating agency methodology which differs from the calculation of the capital structure as reported in Return 14. No regulated dividends were paid on March 31, 2013 and March 31, 2012. Based on discussions with the Company's Treasurer, while the percentage of debt was below the 75% target, as measured by the rating agency, a decision was made to not pay a dividend as would otherwise be paid based on the above noted policy. The Company noted this was because of the unrealized gains included in the AOCI component of equity related to the market to market adjustment on the sinking fund.

Revenue Requirement

Scope: ***Conduct an examination of depreciation, fuel, power purchased, operations and administration expenses, and interest to assess their reasonableness and prudence in relation to sales of power and energy.***

The following table provides a breakdown of the revenue requirement for the years 2009 to 2012, including variances between 2012 and 2011:

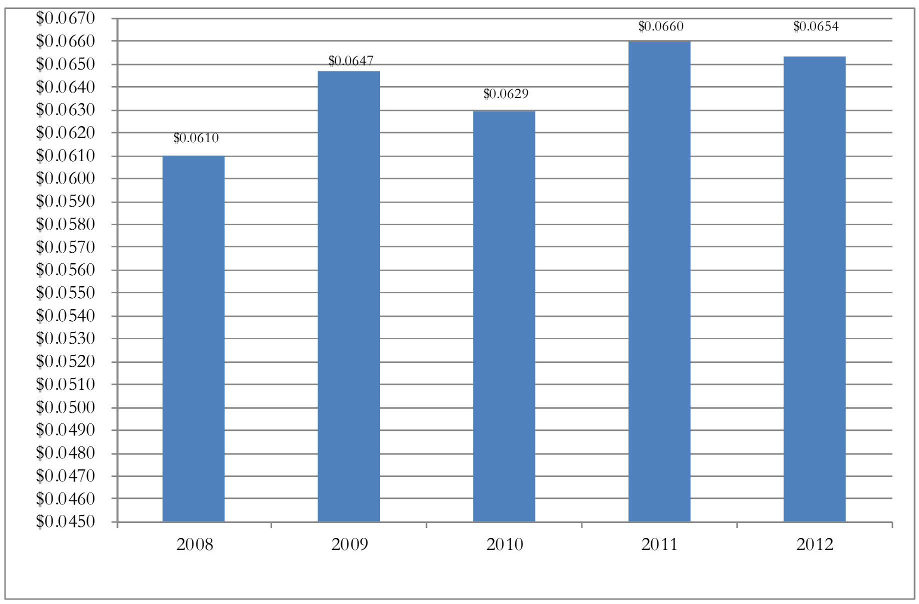
(000)'s		Actuals 2012	Actuals 2011	Actuals 2010	Actuals 2009	Variances 2012-2011
Depreciation		**$ 47,580**	$ 45,684	$ 43,790	$ 41,744	$ 1,896
Fuel		**132,003**	131,276	137,994	136,933	727
Power purchased		**56,986**	52,221	44,244	46,782	4,765
Other costs						
Salaries and fringe benefits		**90,907**	87,556	82,517	76,381	3,351
System equip. maint.		**20,261**	21,512	21,748	22,122	(1,251)
Insurance		**2,109**	1,965	1,960	1,937	144
Transportation		**3,600**	3,377	3,056	3,038	223
Office supplies		**2,230**	2,307	2,100	2,161	(77)
Bldg. rentals and maint.		**1,027**	1,172	1,170	1,145	(145)
Professional services		**7,324**	6,092	4,215	3,612	1,232
Travel		**2,979**	2,977	2,755	2,910	2
Equipment rentals		**1,699**	1,636	1,738	1,721	63
Miscellaneous		**5,144**	4,736	3,829	8,065	408
Loss on disposal		**5,396**	925	687	1,267	4,471
Write down of Assets		**-**	-	-	506	-
	Sub-total	**142,676**	134,255	125,775	124,865	8,421
Allocations						
Other - IOCC		**(2,215)**	(2,292)	(2,648)	(1,875)	77
Hydro capitalized		**(20,723)**	(21,276)	(20,716)	(17,164)	553
Cost recoveries		**(7,874)**	(5,198)	(4,748)	(4,190)	(2,676)
	Sub-total	**(30,812)**	(28,766)	(28,112)	(23,229)	(2,046)
	Total	**111,864**	105,489	97,663	101,636	6,375
Interest		**89,961**	90,844	86,766	83,440	(883)
Regulated earnings		**16,900**	20,599	6,604	17,211	(3,699)
Revenue requirement		**$ 455,294**	$ 446,113	$ 417,061	$ 427,746	$ 9,181

As noted in the above table, the net impact on regulated earnings for 2012 was a decrease from 2011 of $3.7 million. This decrease was primarily attributable to an increase in depreciation of $1.9 million, an increase in power purchased of $4.8 million, an increase in salaries and fringe benefits of $3.4 million, an increase in professional services of $1.2 million, and an increase in the loss on disposal of $4.5 million. The impact of this increase in expenses was partially offset by an increase in revenue of $9.2 million and an increase in cost recoveries of $2.7 million.

In the table and graph below we have provided an analysis of the breakdown of the cost of energy on the basis of the number of kWhs sold for the years 2008 to 2012:

Year	kWh sold and used	Depreciation	Fuel	Purchased Power	Other Costs	Interest	Regulated Earnings	Total Cost of Energy	Cost per kWh
2008	7,004,000	$ 40,393	$ 149,854	$ 41,388	$ 99,275	$ 87,610	$ 8,874	$ 427,394	$ 0.0610
2009	6,612,000	$ 41,744	$ 136,933	$ 46,782	$ 101,636	$ 83,440	$ 17,211	$ 427,746	$ 0.0647
2010	6,627,000	$ 43,790	$ 137,994	$ 44,244	$ 97,663	$ 86,766	$ 6,604	$ 417,061	$ 0.0629
2011	6,758,000	$ 45,684	$ 131,276	$ 52,221	$ 105,489	$ 90,844	$ 20,599	$ 446,113	$ 0.0660
2012	6,964,000	$ 47,580	$ 132,003	$ 56,986	$ 111,864	$ 89,961	$ 16,900	$ 455,294	$ 0.0654

Cost of Energy per kWh

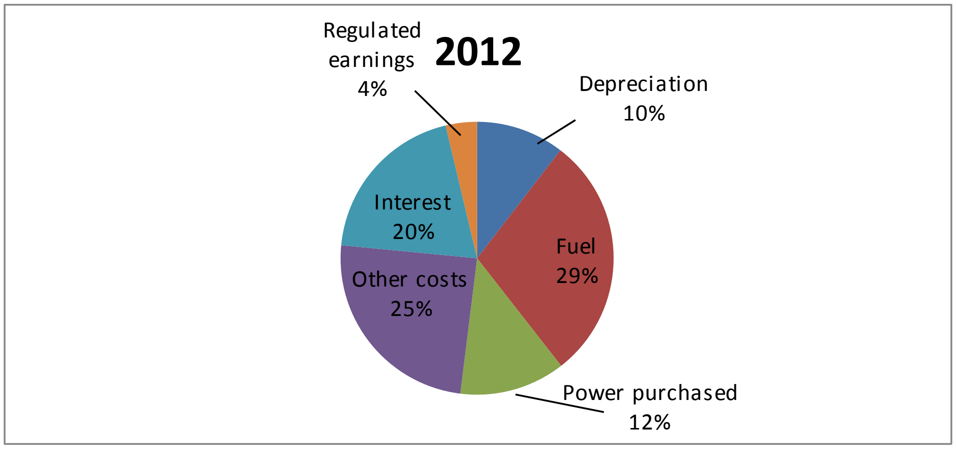


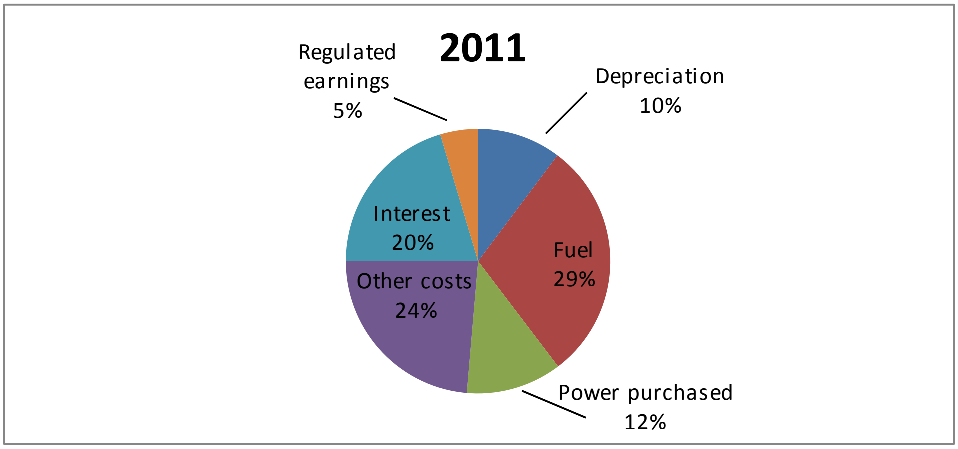
Year over year % change:	6.0%	-2.7%	4.9%	-0.9%

As highlighted in the graph above, the cost per kWh decreased in 2012. In 2012 the cost of energy sold on the basis of the number of kWhs sold was $0.0654 per kWh which represented a 0.9% decrease over 2011.

1 The following table and charts provide a further breakdown of the expense per kWh by expense
2 category for the years 2011 and 2012:
3

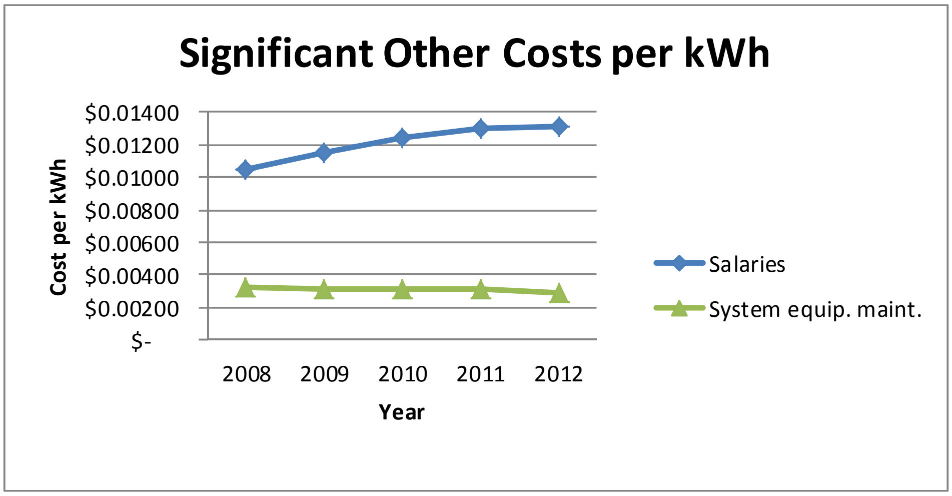
	2012			2011		
kWh sold and used	6,964,000			6,758,000		
	Cost	Cost per kWh	% of Total	Cost	Cost per kWh	% of Total
Depreciation	$ 47,580	0.0068	10.45%	$ 45,684	0.0068	10.24%
Fuel	132,003	0.0190	28.99%	131,276	0.0194	29.43%
Power purchased	56,986	0.0082	12.52%	52,221	0.0077	11.71%
Other costs	111,864	0.0161	24.57%	105,489	0.0156	23.65%
Interest	89,961	0.0129	19.76%	90,844	0.0134	20.36%
Regulated earnings	16,900	0.0024	3.71%	20,599	0.0030	4.62%
Total	$ 455,294	0.0654	100.00%	$ 446,113	0.0660	100.00%

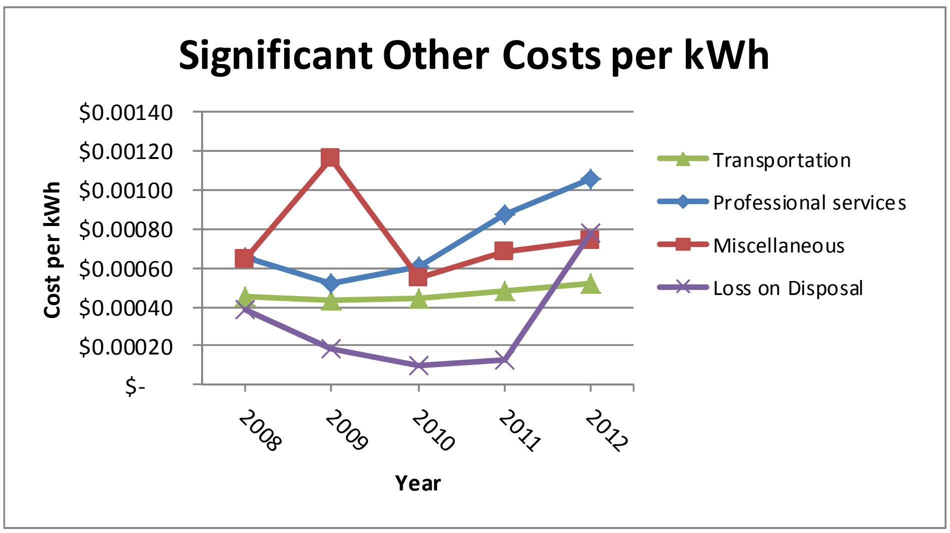




4
5
6
7 Explanations for the significant fluctuations within each of these cost categories are discussed further in
8 this report.

An analysis of the most significant accounts within "other costs" for the years 2008 to 2012 has been provided below in the following two graphs:





In the first graph, cost of salaries and fringe benefits per kWh have increased 0.8% in 2012 and the cost per kWh for system equipment maintenance has decreased by approximately 5.8%. The second graph shows professional services costs per kWh have increased by 20.2%, miscellaneous expenses increased by 8.6%, transportation expense increased by 6.6%, and the loss on disposal increased by 483.4%.

As previously mentioned, we have reviewed the various expense categories in more detail on an individual basis and our observations and comments are noted further in this report for your consideration.

Fuels

Fuel expense in 2012 totaled $132.0 million compared to the 2012 budget of $181.0 million and actual of $131.3 million in 2011. The increase in fuel expense from 2011 levels was approximately $727,000. In comparison to budget, the 2012 actual costs were $49.0 million lower. The breakdown of costs within the fuel category is noted below for the years 2009 to 2012 and the 2012 budget:

(000)'s	2012	2012 Budget	2011	2010	2009	Var 12-12B	Var 12-11
No.6 Fuel	**$164,001**	$184,268	$135,136	$100,674	$80,585	($20,267)	$28,865
Fuel Additives	**44**	84	126	178	89	(40)	(82)
Fuel Costs Indirect	**75**	82	61	63	69	(7)	14
Environmental Handling Fee	**24**	21	12	28	10	3	12
Ignition Fuel	**389**	261	389	296	244	128	-
Gas Turbine Fuel	**877**	817	395	1,197	1,015	60	482
Diesel Fuel Rural	**15,927**	17,049	16,013	12,224	12,631	(1,122)	(86)
Rate Stabilization Plan (RSP)	**(49,334)**	(21,579)	(20,856)	23,334	42,290	(27,755)	(28,478)
	$132,003	$181,003	$131,276	$137,994	$136,933	($49,000)	$727

No. 6 Fuel

In 2012, the total cost of No. 6 Fuel, which is the largest component of fuel expense, increased by $28.9 million (21.4%) from 2011. The average cost per barrel increased by 24.9% in 2012 ($114.80 in 2012 vs. $91.92 in 2011) resulting in a $32.7 million price variance. The variance was offset by a $3.8 million volume decrease as there was a 2.8% decrease in fuel consumption.

The budget variance in No. 6 Fuel of ($20.3) million (11.0%) was due to a decrease in the number of barrels used from budget of 394,281 barrels (1,822,819 budgeted vs. 1,428,538 actual) offset by the increase in the average price per barrel from budget of $13.71 ($101.09 budgeted vs. $114.80 actual). This resulted in offsetting monetary differences of $39.9 million and $19.6 million, respectively.

Fuel Additives

The decrease in fuel additives can be attributed to a decrease in Holyrood fuel's vanadium levels, thus requiring a lower amount of fuel additives. In addition, a 2011 project intended to evaluate the effectiveness of a fuel additive called ACES was discontinued in 2012 at the following three diesel plants: Rigolet, Mary's Harbour, and McCallum.

Gas Turbine Fuel

The Gas Turbine expense increased from 2011 by $482,000 primarily due to increased production requirements and increased fuel usage. Fuel usage consumed at the plant will vary year to year based on a number of factors: monthly tests, troubleshooting, to facilitate outages to other equipment, and for system peaking or contingency reasons. In January 2012, the Hardwoods unit was used for system peaking requirements due to issues with the Holyrood units. This resulted in an increase of $274,000 in fuel costs and an increase in fuel usage of 78,000 gallons. Also, in 2012 there were increased operation requirements for Newfoundland Power Standby generation in order to facilitate several outages and mitigate the customer outage impact. This resulted in an increase of $127,000 in fuel costs.

Diesel Fuel Rural

Diesel Fuel Rural decreased by $86,000 from 2011 and $1,122,000 from the 2012 budget. The budget variance can be attributed to fish plant closures during the year. A new fish plant in Mary's Harbour, with bigger loads, was originally scheduled to open in April 2012 however the opening of this plant was delayed until 2013.

Rate Stabilization Plan (RSP) (the Plan)

Including RSP adjustments, the cost of No. 6 Fuel for 2012 was $114.7 million compared to $114.3 million in 2011 and $162.7 million for the 2012 budget.

The variation in the RSP consists of four main components: fuel variation, hydraulic variation, load variation, and Labrador interconnected.

(000)'s	2012	2011	Variance 12-11
Hydraulic Variation	**$10,831**	**$3,302**	$7,529
Load Variation	**24,645**	**29,497**	(4,852)
Fuel	**(84,592)**	**(53,479)**	(31,113)
Labrador Interconnected	**(218)**	**(176)**	(42)
	($49,334)	**($20,856)**	($28,478)

As noted in the table above, the most significant of these variations contributing to the net RSP variance of $28.5 million is fuel. The fuel variation is calculated using the actual cost per barrel of No. 6 fuel relative to the cost of service (COS) price applied to the number of barrels of fuel consumed. The calculation of this fuel variation is provided in the table below.

Fuel Variation	2012	2011	Variance
Actual barrels adjusted for non-firm sales (000)'s	1,429	1,470	(41)
Average Actual Fuel	114.80	91.92	
Average COS Fuel	55.47	55.47	
Annual fuel price variance	$ (59.33)	$ (36.45)	(22.88)
Fuel Variation (000)'s [1]	$ (84,592)	$ (53,479)	$ (31,113)

	(000)'s Production	Average Price	(000)'s Variance
Fuel Price Variance Increase	1,429	(22.88)	(32,696)
Volume Decrease	(41)	(36.45)	1,494
Annualized calculated variance [2]			(31,201)

1 This number has been calculated on a monthly basis.
2 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

The table above shows that the actual average fuel price for No. 6 fuel in 2012 was $59.33 per barrel higher than the average COS fuel price. This increase in fuel prices resulted in a negative fuel variation of approximately $84.6 million to the Plan in 2012 compared to a $53.5 million negative variation in 2011. The change in the fuel price variation partially offset by the change in fuel consumption led to an increase in the RSP fuel component of $31.2 million (calculated on a monthly basis) for 2012 compared to 2011. As shown above, the increase in fuel costs, relative to the COS, led to a negative fuel price variance of approximately $32.7 million. The negative fuel price variance was partially offset by a positive volume variance of approximately $1.5 million, for a combined variance of $31.2 million (there is a slight difference when the calculation is done on an annualized basis in comparison to a monthly basis).

The hydraulic production in 2012 contributed positively to the RSP in the amount of $10.8 million, this contribution is $7.5 million more than the prior year contribution of $3.3 million.

Hydraulic Variation		**2012**	**2011**	**Variance**
Average COS Fuel ($)		$ 55.47	$ 55.47	$ -
Actual Hydraulic Production (000)'s		4,590,159	4,502,154	
COS Hydraulic Production (000)'s		4,472,070	4,472,070	
Annual hydraulic production variance (000's)		118,089	30,084	88,005
Hydraulic variation (000)'s	**1 2 3**	$ 10,831	$ 3,250	$ 7,581

		(000)'s Production	Average Price	(000)'s Variance
Fuel Price Increase		118,089	$ -	$ -
Hydraulic Production Variance Increase		88,005	$ 55.47	$ 7,749
Annualized calculated variance (000)'s	**4**			$ 7,749

Notes:

1 Holyrood conversion factor in COS is 630 kWh/bbl.

2 This number has been calculated on a monthly basis

3 The Hydraulic variation of $7,581,000 noted differs by $52,000 from reported balance of $7,529,000 in 2012 due to an error of $52,000 in the calcuation of station service readings which related to 2010 and was adjusted early in 2011.

4 Calculation is done on an annualized basis for comparision purposes and will lead to slight differences from a monthly basis.

An increase in hydraulic production of 118 GWh in 2012 over the COS has led to a total savings to the plan of $10.8 million. An increase in actual hydraulic production of 88 GWh compared to 2011 resulted in an increase in the RSP hydraulic component of $7.5 million (calculated on a monthly basis) when compared to 2011.

Load Variation

The load variation for 2012 contributed positively to the Plan in the amount of $24.6 million. The load variation is primarily the result of the load requirements for industrial customers being 484.6 GWh below the COS load requirement. The 2011 variance between actual load requirement and COS was 583.4 GWh. The decrease in load requirements experienced by the pulp and paper industry in the Province is the primary reason for the continued increase in the load variation.

The increase in the actual load requirement experienced in 2012 as compared to 2011 resulted in a decrease in the load variation of $4,852,000. The increase in GWh's for industrial customers in 2012 as compared to 2011 (409.6 in 2012 vs. 310.9 in 2011), is primarily attributable to increased sales for Corner Brook Pulp and Paper Ltd. and North Atlantic Refinery, offset by a decrease in sales to C.F.B. Goose Bay.

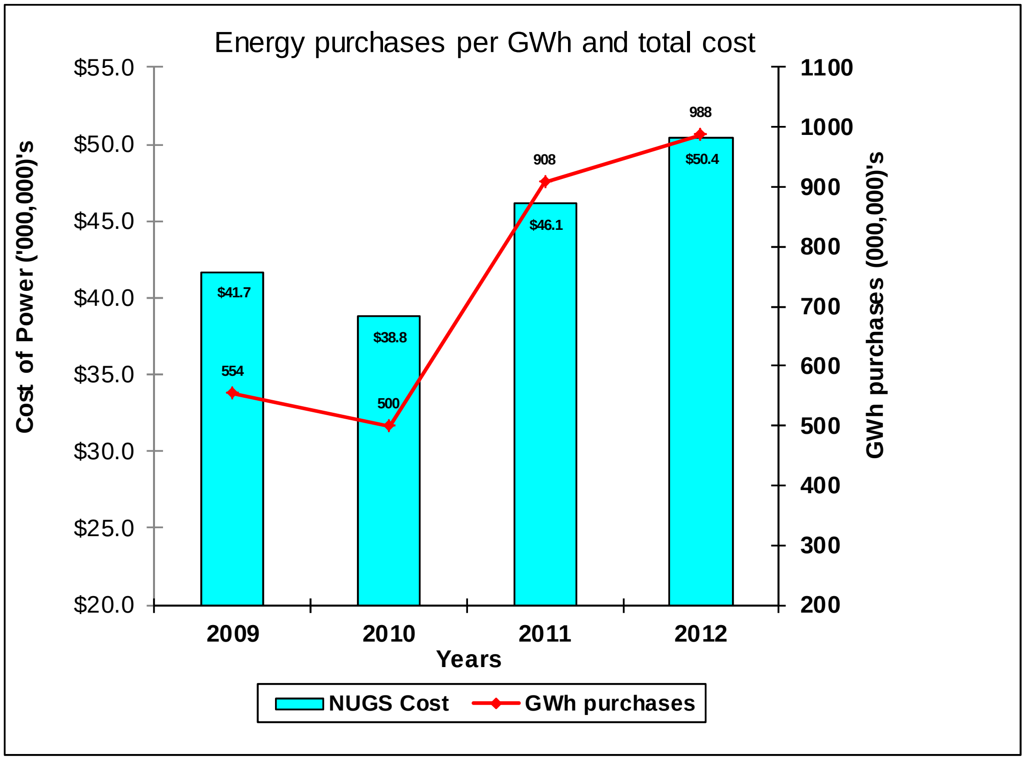
Power purchased

The breakdown of power purchased by account is as follows:

(000)'s	2012	2011	2010	2009	12- 11
Energy Costs - NUGS	**$50,368**	**$46,127**	**$38,831**	**$41,673**	$4,241
Demand & energy - CF(L)Co	**2,024**	**1,914**	**2,237**	**2,019**	110
L'Anse au Loup	**2,931**	**2,890**	**2,054**	**1,644**	41
Island wheeling	**646**	**601**	**591**	**556**	45
Secondary energy	**321**	**-**	**(74)**	**444**	321
Capacity Expansion	**400**	**581**	**491**	**352**	(181)
Ramea Wind	**162**	**108**	**114**	**94**	54
Ramea Hydrogen	**134**	**-**	**-**	**-**	134
	$56,986	**$52,221**	**$44,244**	**$46,782**	$4,765

Energy purchases from Non-Utility Generators (NUGs) represent the most significant component of purchased power. This category increased by $4.2 million, or 9.2%, in 2012 compared to 2011. This increase is due to an increase in energy purchased in 2012 compared to 2011 with 988 GWh purchased in 2012 compared to 908 GWh purchased in 2011. The increase is primarily related to the power purchased from the base generation at Nalcor Exploits Facilities (2012- 730.4 GWh, 2011- 640.4 GWh). Commencing in 2011 and upon direction from the Province, the energy purchase rate for production at the Nalcor Exploits Facilities at Grand Falls – Windsor, Bishop's Falls, Buchans, and Star Lake was made available to Hydro at 4 cents/kWh. This rate remained constant in 2012.

1 The following graphs depict the changes in energy purchases in terms of GWh and total costs followed
2 by the changes in energy purchases in terms of GWh and cost per GWh over the period 2009 to 2012:



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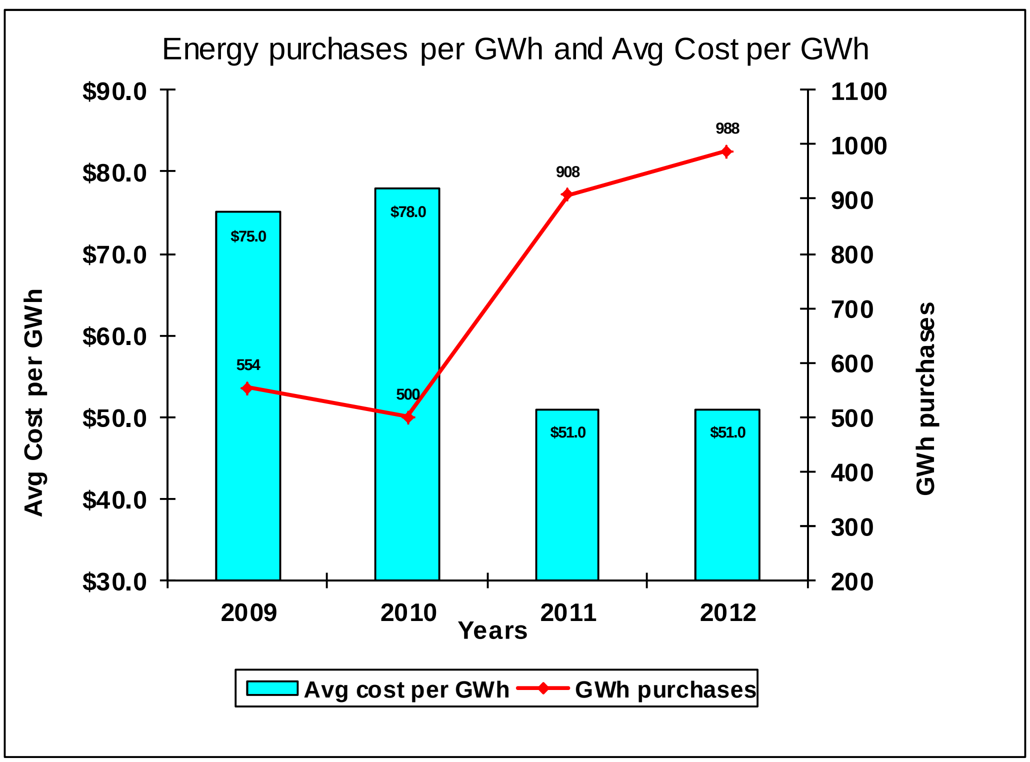

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As shown in these charts, in 2012 the average cost per GWh purchased from NUGS was $51.0 per GWh which was consistent with the cost per GWh in 2011.

The Island wheeling is the power wheeled (or transmitted) over Newfoundland Power's transmission lines to serve Hydro's customers. The customers served by these wheeling arrangements are located in the following communities/areas:

- St. Patricks
- King's Point
- Seal Cove Road
- Coachman's Cove
- Westport
- Fogo (and Change Islands)

For all locations (other than Fogo/Change Islands) there is an energy wheeling rate of $0.0048/kWh. For Fogo/Change Islands there is a fee from Hydro to Newfoundland Power, currently set at $345,156 annually.

The increase of $321,000 in Secondary Energy costs resulted from payments made to Deer Lake Power (DLP) relating to secondary energy purchases. In June 2012, payment was made for the DLP secondary energy that had accumulated from July 2009 to May 2012 (net spill) for which Hydro had previously deferred payment due to Hydro's high reservoir storage conditions. Hydro recorded the Hydraulic DLP generation as if the energy was generated from Hydro's own hydraulic plants which were reflected in the fuel/RSP accounts in Hydro's accounting records. When the DLP power purchase was confirmed in 2012, Hydro adjusted in 2012 the applicable RSP transactions recorded by year from 2009 to 2012 related to hydraulic generation and recorded the DLP power purchase.

The $134,000 in Ramea Hydrogen costs represents avoided fuel costs associated with the Ramea Wind/Hydrogen Project of which $67,000 was applicable to prior years and an additional $67,000 relating to 2012. According to Hydro, the Ramea project is generating wind energy that is displacing use of Hydro diesel fuel energy generation in Ramea. Hydro has agreed to pay Nalcor for the wind energy at the avoided fuel cost. Each month an avoided fuel cost calculation is completed and invoiced from Nalcor to Hydro. The total cost incurred in 2012 for Ramea wind energy is $296,000 which is the combination of the Ramea Wind account of $162,000 relating to a power purchase agreement for wind energy and the $134,000 in avoided fuel costs associated with the Ramea Wind/Hydrogen Project.

The variance in other components of this expense category was less significant on a net basis in 2012 compared to 2011 and no further analysis was conducted.

Salaries and fringe benefits

<u>Analysis of Gross Payroll Costs</u>

Gross payroll costs for 2012 were $90,907,000, an increase of $3,351,000 (3.8%) in comparison to 2011. The increase in 2012 over 2011 was due to various fluctuations within the salaries and employee future benefits cost groupings. These fluctuations are outlined in the table below which summarizes salaries and fringe benefits costs incurred from 2009 to 2012.

(000)'s	2012	2011	2010	2009	Var 12-11
Salaries	**$ 51,818**	$ 48,706	$ 45,402	$ 44,374	$ 3,112
Temporary salaries	**6,272**	7,034	6,700	5,900	(762)
	58,090	55,740	52,102	50,274	2,350
Other salary costs	**562**	668	3,009	2,009	(106)
Intercompany salaries	**2,157**	2,311	1,673	1,127	(154)
	60,809	58,719	56,784	53,410	2,090
Allowances	**1,836**	1,773	1,469	1,309	63
Directors fees	**41**	(3)	55	54	44
Overtime	**10,633**	9,460	8,675	7,778	1,173
Employee future benefits	**6,970**	7,247	6,098	4,334	(277)
Fringe benefits	**8,064**	7,672	7,254	7,029	392
Group insurance	**2,403**	2,546	2,052	2,336	(143)
Labrador travel benefit	**151**	142	130	131	9
	$ 90,907	$ 87,556	$ 82,517	$ 76,381	$ 3,351

The salaries and temporary salaries categories (excluding other salary costs and intercompany salaries) experienced an increase of $2.4 million (4.2%) in comparison to 2011. This increase is primarily due to a general rate increase in non-union and union salaries of 4%.

The increase in overtime in 2012 compared to 2011 is primarily due to an increase in the following:

- Transmission and Rural Operations overtime of $818,000 due to the Black Tickle Diesel Plant Fire, scheduled deadlines for VALE and Labrador City Upgrade;
- An increase of $287,000 in Hydro Generation overtime was mainly attributable to an increase in capital requirements and increased costs incurred to backfill for vacant permanent positions; and,
- Thermal Generation overtime increased by $169,000 in 2012 resulting primarily from an emergency Synchronous Condenser Thrust Bearing repair and unfilled vacancies in 2012.

The breakdown of the salaries category by division is as follows:

(000)'s	2012	2011	2010	2009	Var '12-11
Executive Leadership & Assoc.	**$ 367**	$ 345	$ 334	$ 368	$ 22
Human Resources & Org. Effect.	**4,136**	3,891	3,349	3,295	245
Finance/CFO	**6,123**	6,039	6,281	6,652	84
Project Execution & Tech Services	**6,565**	7,034	8,209	7,246	(469)
Regulated Operations	**40,076**	38,060	33,660	34,293	2,016
Corporate Relations (Note 1)	**2,519**	2,425	2,150	-	94
Recharged salaries	**(1,696)**	(2,054)	(1,881)	(1,580)	358
	$ 58,090	$ 55,740	$ 52,102	$ 50,274	$ 2,350

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The Project Execution & Tech Services divisional salaries decreased by $469,000 over 2011 primarily due to a net reduction of 15 average full-time equivalents ("FTE's") in 2012 over 2011 offset by salary increases for employees in 2012.

The increase of $2,016,000 (5.3%) in Regulated Operations has been primarily attributed to the following:

- Permanent salaries increased due to the collective agreement rate increases effective April 1, 2012 (4%);
- TRO temporary salaries increased by $356,000 (1.0%) due to the Black Tickle Diesel Plant Fire, the commissioning of new terminal stations in Labrador West and Muskrat Falls, the generator failure in Nain, and the demand for more service stations; and,
- Hydro Generation temporary salaries increased by $104,000 (0.3%) due to the use of temporary staff to backfill vacant permanent positions.

These increases were offset by an $115,000 decrease (0.3%) in Thermal Generation temporary salaries due to the completion of the Blanks & Blinds Capital project in 2011, a safety initiative which did not occur in 2012.

Recharged salaries consist of an employee's time being charged to another division when he/she is working on a project that is not forecast in his/her current division. Generally recharged salaries should net to $Nil for the year; however, because of recharges to non-regulated activities, a credit balance will normally remain in this account.

Consistent with 2011, the Company has implemented a salary compensation matrix for non-union employees. The matrix illustrates a scale for salary increases and bonuses based on performance ranging from 0-10% (inclusive of a 4% general adjustment). The compensation matrix allows for pay adjustments above the scale maximum based on an employee's "rating of performance". Ratings of performance include Unacceptable, Improvement Required, Meets Expectations, Exceeds Expectations, and Exceptional.

As noted by the Company, all salary adjustment figures include a general scale adjustment of 4% and all are calculated as a percentage of current base salary. All salary adjustments are subject to a scale maximum. Those in the Exceeds Expectations and Exceptional categories whose performance adjustment would exceed the scale maximum receive the balance in the form of a one-time cash bonus of 3% or 6%, respectively, of their base salary.

There have been no changes in the compensation matrix from 2011 as follows:

	Scale Adjustment - Below Scale Maximum	
Rating of Performance	**2012**	**2011**
Exceptional	10% (with cash payout of balance)	10% (with cash payout of balance)
Exceeds Expectations	8.5% (with cash payout of balance)	8.5% (with cash payout of balance)
Meets Expectations	7% (to the scale maximum)	7% (to the scale maximum)

Full-Time Equivalents ("FTE")

The table below is a detailed comparison of the average number of full-time equivalent (FTE) employees by division for 2009 to 2012. The table was compiled from quarterly FTEs provided by Hydro and taking the average for the year. As shown, in comparison to 2011 the total FTEs for 2012 decreased by 20 full time positions.

	2012	2011	2010	2009	Var '12-11
Executive Leadership & Assoc.	**14**	4	5	6	10
Human Resources & Org. Effect.	**61**	63	56	51	(2)
Finance/CFO	**79**	91	106	111	(12)
Project Execution & Tech Services	**72**	87	100	84	(15)
Regulated Operations	**525**	525	499	539	-
Corporate Relations (Note 1)	**39**	40	40	-	(1)
	790	810	806	791	(20)

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The salary costs as detailed earlier in the report have been normalized for special payments outside of regular wage expense. The results of our analysis for 2009 to 2012 are included in the following table:

(000's)

	2012	2011	2010	2009
Salary costs (including temporary salaries)	**$ 58,090**	$ 55,740	$ 52,102	$ 50,274
Less: Retiring allowances and redundancy pay	**(1,263)**	(1,066)	(1,118)	(1,116)
	56,827	54,674	50,984	49,158
FTE (including exeuctive members)	**790**	810	806	791
Average salary per FTE	**$ 71,933**	$ 67,499	$ 63,256	$ 62,147
% increase	**6.57%**	6.71%	1.78%	6.29%

The above analysis indicates that the average salary per FTE has increased by 6.57% which is primarily due to general salary increase granted during the year.

Executive salaries

The salaries of the executives of Nalcor are recharged back to Hydro via the Intercompany Salary account. The billing rates are designed to cover salary, benefits, and vacation of the executives.

The table below outlines the portion of executive salaries, including the total hours and average billing rates, which were charged back to Hydro by Nalcor for years 2012 to 2010:

	2012			2011			2010		
	Hours	**Average Billing Rate**	**Recharge Amount**	Hours	Average Billing Rate	Recharge Amount	Hours	Average Billing Rate	Recharge Amount
CEO	**154.5**	**$ 417.20**	**$ 64,457**	133.5	$ 402.45	$ 53,727	172.0	$ 362.31	$ 62,317
VP, HR	**392.5**	**169.14**	**66,389**	996.0	161.36	160,719	1,165.5	152.31	177,515
VP, Project Execution (Note 1)	**451.5**	**205.55**	**92,805**	697.0	195.36	136,168	192.5	186.59	35,919
VP, Finance	**48.0**	**208.69**	**10,017**	88.5	198.41	17,559	92.0	186.59	17,166
VP, Corporate Relations	**265.5**	**141.92**	**37,680**						
VP, Engineering services (Note 1)							1,249.0	131.38	164,093
	1,312.0	**$ 206.82**	**$ 271,348**	1,915.0	$ 192.26	$ 368,173	2,871.0	$ 159.18	$ 457,010
% change	**-31%**	**8%**	**-26%**	-33%	21%	-19%	-1%	41%	40%

Note 1: In October 2010 Vice President of Project execution and Technical Services was hired replacing the executive position of Vice President, Engineering Services.

During 2012 total recharge amount from executives decreased by $96,825 (26%) compared to 2011 due to a decrease of 603 hours (31%) partially offset by a 8% increase in the weighted average billing rate.

The following table outlines the change in executive hours from Nalcor to Hydro and billing rates from 2011 to 2012:

	2012 - 2011			
	Change in Hours	**Change in Hours (%)**	**Change in Billing Rate ($)**	**Change in Billing Rate (%)**
CEO	21.00	15.7%	14.75	3.7%
VP, HR	(603.50)	(60.6%)	7.78	4.8%
VP, Project Execution	(245.50)	(35.2%)	10.19	5.2%
VP, Finance	(40.50)	(45.8%)	10.28	5.2%
VP, Corporate Relations	265.50	N/A	141.92	N/A
	(603.00)	(31.5%)		

Executive billing rates increased from 2011 to 2012 on an individual basis ranging from 3.7% to 5.2%.

Capitalized salaries

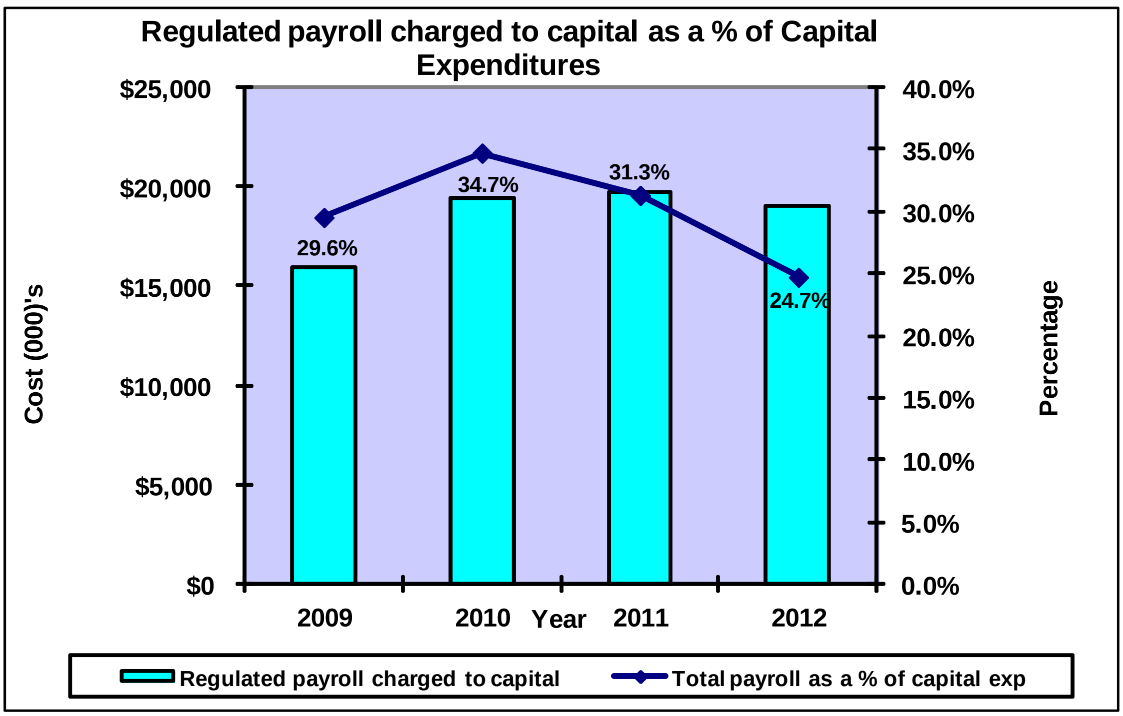
Capitalized salaries include the salaries and benefits of the Company's employees whose time is charged directly to capital projects. The gross payroll costs for 2009 to 2012 were allocated to operations and capital as follows:

(000)'s	**2012**	**2011**	**2010**	**2009**	**Var 12-11**
Payroll charged to operating	**$71,856**	$67,821	$63,063	$60,422	$4,035
Payroll charged to capital	**19,051**	19,735	19,456	15,959	(684)
	$90,907	$87,556	$82,519	$76,381	$3,351

The Company's 2012 capitalized payroll is $684,000 lower than 2011. The amount of capitalized salaries can vary widely from year to year depending on the type of capitalized projects and the requirement for manpower versus machine power. The percentage of capital salaries in relation to the amount of capital expenditures can also fluctuate from year to year.

The following table and graph illustrate the relationship between payroll charged to capital and capital expenditures for the period 2009 to 2012.

(000)'s	**2012**	**2011**	**2010**	**2009**
Capital expenditures [1]	**$77,000**	$63,000	$56,000	$54,000
Regulated payroll charged to capital	**19,051**	19,735	19,456	15,959
Total payroll as a % of capital exp	**24.7%**	31.3%	34.7%	29.6%



[1] Balance includes both regulated and non-regulated costs

As noted from the table above, the percentage of capital salaries in relation to the amount of capital expenditures can fluctuate significantly from year to year.

As noted in the table below capitalized salaries consists of three sub-categories of costs: capital salaries, capital overtime, and capital overhead.

(000)'s	2012	2011	2010	2009	Var 12-11
Capital salaries	**$14,009**	$12,597	$12,930	$9,998	$ 1,412
Capital overtime	**5,042**	4,530	4,417	3,449	512
Capital overhead	**-**	2,608	2,109	2,512	(2,608)
	$19,051	$19,735	$19,456	$15,959	$ (684)

Capital salaries, which make up the largest portion of this category, experienced an increase of $1,412,000 in 2012 and capital overtime experienced an increase of $512,000 over 2011. The charge out of the capital allocation was discontinued in 2012 as a result of a new accounting policy adopted as approved by the Board in P.U.13 (2012) which resulted in a $Nil balance in capital overhead this year. Employees whose costs were previously charged to this allocation now only charge labour costs to capital projects if their labour is directly related to a specific capital project.

System equipment maintenance

In 2012 system equipment maintenance costs decreased from 2011 levels by approximately $1.3 million. The following table summarizes system equipment maintenance costs incurred from 2009 to 2012 by sub-category.

(000)'s	2012	2011	2010	2009	Var 12-11
Maintenace material	**$ 9,784**	$ 10,961	$ 17,780	$ 17,899	$ (1,177)
Contract Labour (Note 1)	**8,378**	7,312	-	-	1,066
Contract Materials (Note 1)	**21**	57	-	-	(36)
Extraordinary Repair Amortization	**605**	1,644	2,582	2,715	(1,039)
	18,788	19,974	20,362	20,614	(1,186)
Tools and operating supplies	**415**	349	398	369	66
Freight expense	**383**	471	399	411	(88)
Lubricant, gases & chemicals	**675**	718	589	728	(43)
	$ 20,261	$ 21,512	$ 21,748	$ 22,122	$ (1,251)

Note 1: Prior to 2011, contract labour and contract materials were included in Maintenance material.

The total maintenance material, extraordinary repair amortization, contract labour and contract materials costs in 2012 decreased by $1,186,000 (or 5.9%) from 2011. Maintenance costs are incurred throughout all divisions with the majority of costs incurred in the Regulated Operations division. The following table provides a breakdown of Maintenance costs by division for 2009 to 2012.

(000)'s	2012	2011	2010	2009	Var 12-11
Executive Leadership & Associates	**$ -**	$ -	$ 3	$ 71	$ -
Human Resources & Org. Effect.	**26**	46	190	135	(20)
Finance/CFO	**1,306**	1,212	1,317	1,173	94
Project Execution & Tech Services	**133**	161	189	131	(28)
Regulated Operations (Note 1)	**17,185**	18,377	18,483	19,104	(1,192)
Corporate Relations (Note 2)	**138**	178	180	-	(40)
	$ 18,788	$ 19,974	$ 20,362	$ 20,614	$ (1,186)

Note 1: Regulated operations includes extraordinary repair amortization.

Note 2: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The decrease of $1,192,000 from 2011 levels in the Regulated Operations division is primarily due to a decrease in the amortization of extraordinary repairs in 2012. In 2011, amortization included $1,343,000 (2012 - $605,000) relating to an Asbestos Abatement, as well as $302,000 (2012 - $Nil) relating to Unit #2 boiler repairs. The extraordinary repairs were fully amortized in October, 2012.

The following table provides a departmental breakdown of maintenance material costs in the Regulated Operations Division.

(000)'s	2012	2011	2010	2009	Var 12-11
System Operation	**$ 3**	$ 3	$ 2	$ 215	$ -
Hydro Generation	**2,153**	1,392	1,385	1,190	761
Thermal Holyrood*	**7,433**	9,599	9,437	10,664	(2,166)
Central Operations	**5,539**	5,231	5,291	4,684	308
Labrador Operations	**1,132**	1,331	1,323	1,429	(199)
Northern Operations	**925**	821	1,045	922	104
	$ 17,185	$ 18,377	$ 18,483	$ 19,104	$ (1,192)

* Thermal Holyrood indudes extraordinary repair amortization.

The $761,000 increase in costs in the Hydro Generation department is primarily attributed to costs incurred in 2012 relating to the Bay D'Espoir Access Road Rebuild, the Bay D'Espoir Surge Tank Operating Project, and the Bay D'Espoir Draft Tube Deck Operating Project.

The $308,000 increase in costs in the Central Operations department in 2012 over 2011 is primarily attributable to increased work on Hydro's vegetation control program in high priority remote areas where worker safety and system reliability are at most risk.

The largest cost incurred in 2012 in regulated operations division is in the Thermal Holyrood department. Material maintenance expenditures in this division relate to the type of annual maintenance incurred on each of the three thermal units in Holyrood plus the routine maintenance requirements on the structures and equipment around and in the plant. A breakdown of costs at the Holyrood thermal plant is as follows:

(000)'s	2012	2011	2010	2009	Var 12-11
Unit # 1	**$1,517**	$832	$1,555	$3,583	$685
Unit # 2	**1,668**	2,708	477	1,170	(1,040)
Unit # 3	**1,024**	1,943	2,374	521	(919)
Annual routine maintenance*	**3,224**	4,116	5,031	5,390	(892)
	$7,433	$9,599	$9,437	$10,664	($2,166)

* Annual routine maintenance includes extraordinary repair amortization.

The increase in Unit #1 primarily relates to a full-scope overhaul completed in 2012 in comparison to a reduction in the scope of the annual broiler overhaul on Unit #1 in 2011. According to the Company, due to a cleaner burning fuel (0.7% Sulphur) and less operating hours of each unit, there were cost savings in 2011 whereby one of the three units received an inspection and minor cleaning only, without the full overhaul.

The decrease in Unit #2 primarily relates to the fact that there was a minor valve overhaul in 2011 that did not occur in 2012.

The decrease in Unit #3 primarily relates to Brush Gear failure repairs which occurred in 2011 but not in 2012, and there was a minor boiler overhaul performed on Unit #3 in 2012 in comparison to the full-scope overhaul completed in 2011.

The decrease in annual routine maintenance primarily relates to the decrease in the amortization of extraordinary repairs of $1.0 million in 2012 as explained earlier.

Professional services

Professional services costs for 2012 were $7,324,000 which increased from 2011 levels by approximately $1,232,000 (or 20.2%). A breakdown of the cost categories within professional services for 2009 to 2012 is outlined below.

(000)'s	2012	2011	2010	2009	Var 12-11
Consultants	**$4,145**	$3,024	$2,335	$2,114	$1,121
PUB Related Costs	**1,835**	1,934	882	939	(99)
Software Aquisitions & Maintenance	**1,344**	1,134	998	559	210
	$7,324	$6,092	$4,215	$3,612	$1,232

The increase of $210,000 in Software Acquisitions & Maintenance costs was primarily due to a $164,000 increase in support costs relating to OSI Monarchs software, PI software, and CCS web application support. Hydro also incurred an increase in costs of $30,000 relating to the acquisition of additional software licenses and $23,000 relating to the acquisition and maintenance of additional Symantec software.

Consultants' fees which represent the largest portion of total professional fees were approximately $4.1 million in 2012. The table below summarizes these fees by department.

(000)'s	2012	2011	2010	2009	Var 12-11
Executive Leadership & Associates	**$201**	$90	$99	$231	$111
Human Resources & Organization Effectiveness	**777**	846	639	465	(69)
Finance/CFO	**494**	277	285	263	217
Project Execution & Tech Services	**477**	311	331	316	166
Regulated	**1,157**	910	592	839	247
Corporate Relations (Note 1)	**1,039**	590	389	-	449
	$4,145	$3,024	$2,335	$2,114	$1,121

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The increase of $111,000 in the Executive Leadership & Associates department is primarily due to legal fees related to customs duties on Fuel Oil No. 5 and Fuel Oil No. 6, and an increase in audit fees related to IFRS, insurance proceeds and the depreciation study.

The decrease of $69,000 in the Human Resources & Operation Effectiveness is primarily due to the higher expenses in 2011 relating to Emergency Response Program.

The increase of $217,000 in the Finance department is primarily due to the following items incurred in 2012: Pole Attachment Survey, RFP Contract Review, and Backfill for Helpdesk Leave.

The increase of $166,000 in the Project Execution & Tech Services department is primarily due to an increase of $287,000 in Project Management Service, Bay D'Espoir Station Services and Ampacities partially offset by a decrease of $135,000 in Resource Leveling and Consulting Services.

The increase of $247,000 in the Regulated department is primarily due to the following events which occurred in 2012: the Diesel Plant Fire Protection Study, the English Harbour West transformer oil cleanup, the Pole Survey and Environment Site Assessment - L'anse Au Loup operating project, and the Holyrood Thermal Generating Station De-commissioning Study.

The increase of $449,000 in Corporate Relations is primarily due to an increase in consulting services related to the management of the energy efficiency programs.

Miscellaneous

Miscellaneous expense in 2012 increased by approximately $408,000, or 8.6%, from 2011. A breakdown of the cost categories within Miscellaneous for 2009 to 2012 is outlined below:

(000)'s	2012	2011	2010	2009	Var 12-11
Business and payroll taxes	**$ 3,177**	$ 2,967	$ 2,933	$ 2,807	$ 210
Bad debt expense	**134**	116	(631)	3,884	18
Staff training	**780**	647	668	730	133
Write offs	**329**	179	239	105	150
Employee expenses	**354**	427	347	332	(73)
Sundry costs	**197**	142	161	128	55
Diesel fuel Hydro	**13**	104	70	58	(91)
Energy management	**154**	148	36	13	6
Collection fees	**6**	6	6	8	-
	$ 5,144	$ 4,736	$ 3,829	$ 8,065	$ 408

The $210,000 increase in Business and Payroll Taxes resulted from an increase of $158,000 in municipal tax which is a function of increased rural revenue, along with an increase of $52,000 in payroll taxes resulting from an increase in salaries paid out in 2012.

Staff training costs increased by $133,000 in 2012 due to an increase in training costs in the following business units: TRO Central experienced an increase of $52,000 due to Infrared Camera training and Class 3 training; TRO Network Services experienced an increase of $63,000 which was attributable to training relating to the replacement of outdated microwave radio, coupled with battery training.

The $150,000 increase in Write Offs resulted from the identification of obsolete inventory in Holyrood and Bishops Falls. Hydro noted it has increased its effort to review inventory which has resulted in an increase in inventory adjustments.

Loss on disposal

In 2012, loss on disposal of assets totaled $5,396,000 compared to the 2011 loss of $925,000. A breakdown of this increase of approximately $4,471,000, or 483.4% compared to 2011 is provided below:

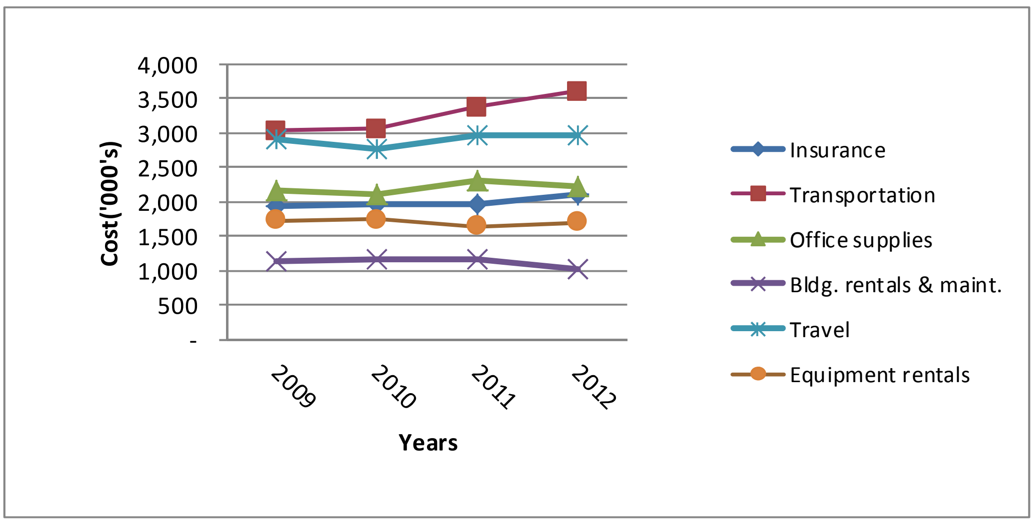
(000)'s	2012	2011	2010	2009	Var 12-11
Net book value of disposed assets	**$5,356**	$1,226	$1,150	$2,563	$4,130
Asset removal costs	**1,182**	-	-	-	$1,182
Disposal proceeds	**(1,156)**	(313)	(480)	(1,319)	(843)
Auction fees and expenses	**14**	12	17	23	2
	$5,396	$925	$687	$1,267	$4,471

As is evident in the table above, the net book value of the disposed assets, which encompasses much of the costs associated with the loss on the disposal of capital assets, tends to vary from year to year. In 2012, the largest disposals related to partial asset disposals of the Cat Arm dam, Cat Arm road, Black Tickle Diesel Plant, Happy Valley North Plant, and the retirement of distribution poles. In 2012 Hydro created a general ledger account to separately identify capital asset removal costs. In 2012 removal costs were expensed for $1,182,000 primarily relating to voltage conversion in Labrador and upgrade of Fuel Storage in St. Lewis.

Other Costs - remaining account groupings

Variances in the remaining account groupings of Other Costs are detailed in the table and graph below.

('000)'s	2012	2011	2010	2009	Var 12-11
Insurance	**2,109**	1,965	1,960	1,937	144
Transportation	**3,600**	3,377	3,056	3,038	223
Office supplies	**2,230**	2,307	2,100	2,161	(77)
Bldg. rentals & maint.	**1,027**	1,172	1,170	1,145	(145)
Travel	**2,979**	2,977	2,755	2,910	2
Equipment rentals	**1,699**	1,636	1,738	1,721	63
Write down of assets	**-**	-	-	506	-



Explanations of the larger variances in the remaining account groupings are as follows:

- the increase of $144,000 in insurance costs is mainly due to a 12% increase in the property insurance rate structure for the Boiler & Machinery, resulting from a number of claims and incidents which occurred over the past three years.

- The increase of $223,000 in transportation costs is mainly due to an increase of $185,000 in aircraft and fuel costs. Effective July 1, 2011, daily contracted helicopter rates for Labrador increased by 11% from $1,019/day to $1,130/day. The hourly rate also increased by 21% from $330/hour to $400/hour, along with increased usage in Labrador.

- The decrease of $145,000 in building rentals and maintenance costs is mainly due to a decrease in safety supplies in the following business units: TRO experienced an decrease of $99,000 in their requirement for safety supplies due to a decrease in apprenticeship hiring in 2012; Thermal Generation experienced a decrease of $39,000 due to the supply of insulated jackets in 2011 which did not occur in 2012; Hydro Generation experienced a decrease of $20,000 primarily due to the reduced usage of winter safety clothing in 2012.

Cost Recovery Charges

Cost recovery charges from CF(L)Co. and external sources for 2012 have increased from 2011 by approximately $2,676,000 or 51.5%. The breakdown of cost recovery charges by division is as follows:

(000)'s	2012	2011	2010	2009	Var 12-11
Human Resources &					
Organization Effectiveness	**$ 1,027**	$ 886	$ 956	$ 57	$ 141
Finance	**4,572**	2,858	2,476	2,094	1,714
Project Execution & Tech Services	**-**	-	19	-	**-**
Regulated	**887**	706	883	2,039	181
Corporate Relations (Note 1)	**1,388**	748	414	-	640
	$ 7,874	$ 5,198	$ 4,748	$ 4,190	$ 2,676

Note 1: In 2011 Corporate Relations division was created which includes the department of 'Corporate Communications and Shareholder Relations' (previously included in Executive Leadership) and the departments of 'Customer Service' and 'Energy Efficiency' (previously included in Regulated operations). The 2010 year has been reclassified for this restructuring.

The services provided to CF(L)Co. by Hydro are provided in accordance with a services agreement, which outlines the manner in which services will be charged to CF(L)Co. According to the services agreement, all costs are charged according to Hydro's operating bill rates, fixed charge rate, and an allocation of its intercompany administration fee on appropriate bases. This is consistent with Nalcor's intercompany transaction costing methodology as noted further in this report under the Cost Allocations.

The increase of $1,714,000 in 2012 over 2011 in the Finance division is primarily attributed to an increase in the Intercompany Administration Fee. The Intercompany Administration Fee is examined in more detail in the "Cost Allocation" section of this report.

The increase of $181,000 in the Regulated division in 2012 over 2011 is primarily attributed to an increase in cost associated with Hurricane Leslie which was recoverable from Newfoundland Power in 2012.

The increase of $640,000 in Corporate Relations is primarily due to an increase in 2012 Conservation Demand Management ("CDM" Program costs of $910,622 compared to 2011 offset by recoveries totaling $248,083 received from the Department of Natural Resources in 2011, and not in 2012, to offset costs incurred in relation to the CDM Coastal Labrador Community Pilot Phase II program.

A review of other cost recoveries as well as cost allocations between non-regulated and regulated operations is discussed further in the report under the section entitled 'Non-Regulated Activity'.

Interest

Net interest decreased by approximately $800,000 or 1.0% in 2012 compared to 2011. The following is a summary of interest expense for 2009 to 2012:

(millions)	2012	2011	2010	2009	Var 12-11
Gross interest	**$91.4**	$91.1	$90.9	$91.0	$0.3
Debt guarantee fee	**3.7**	3.9	-	-	(0.2)
RSP	**13.2**	12.2	10.2	7.0	1.0
Amortization of debt discount and financing costs	**0.5**	0.5	0.4	0.4	-
Amortization of foreign exchange losses	**2.2**	2.2	2.2	2.2	-
	111.0	109.9	103.7	100.6	1.1
Less:					
Interest earned	**18.3**	17.6	16.0	16.4	0.7
Interest capitalized during construction	**2.7**	1.5	1.0	0.8	1.2
	$90.0	$90.8	$86.7	$83.4	$ (0.8)

The overall decrease in net interest is mainly attributable to an increase in interest earned and interest capitalized during construction, offset by an increase in RSP interest.

The debt guarantee fee is an annual fee paid by Hydro in return for the Province's guarantee of its debt obligations. In 2008 the Province waived Hydro's requirement to pay the fee while continuing to guarantee Hydro's debt. This waiver continued until 2011 when the fee was reinstated.

The interest rate remained constant in 2012 over 2011 however RSP interest increased by $1.0 million due to growing balances in the RSP. The RSP balance increased from $170 million as at December 31, 2011 to $202 million as at December 31, 2012.

Interest capitalized during construction increased by $1.2 million in 2012 due to an increase in the amount of spending in 2012 along with an increase in the amount in work-in-progress ("WIP") due to multiyear projects and carry over amounts.

Depreciation

Scope: ***Review Hydro's rates of depreciation and assess their compliance with the 2012 Gannett Fleming Depreciation Study relating to plant in service as of December 31, 2009. Assess reasonableness of depreciation expense.***

Our procedures with respect to depreciation were focused on reviewing the rates of depreciation used and assessing its compliance with the Gannett Fleming Depreciation Study dated November 2012 and compliance with Board Order P.U. 40 (2012). In addition, our procedures included assessing the overall reasonableness of depreciation expense.

On December 22, 2011 the Company submitted an application to the Board requesting a change in its depreciation methodology from its current sinking fund and straight line methodologies with fixed service lives for specific classes of assets to straight line depreciation using the average service life procedure applied on a remaining life basis.

On November 14, 2012 a settlement agreement was executed and agreed to by Hydro, the Industrial Customers, and the Consumer Advocate on matters pertaining to the application. The following was agreed to regarding Hydro's application of group depreciation to its assets:

- Hydro's proposal to use the average life group procedure applied on a remaining life basis with effect from January 1, 2011 is appropriate to determine depreciation expense from January 1, 2012 on a go-forward basis with the corresponding adjustment for 2011 to be made in opening retained earnings;
- Hydro's proposal to apply group depreciation rates to individual assets, rather than to total group investment, is acceptable;
- Hydro's proposal to stop accruing depreciation once an asset is fully accrued is acceptable until varied by further Order of the Board; and,
- Hydro's proposal to continue to book, to its income statement, gains and losses related to asset retirements is acceptable until varied by further Order of the Board.

In P.U. 40 (2012) the Board ordered Hydro to:

- Adopt the straight-line method of depreciation for all its assets, with group accounting methods using average service life procedure and applied on a remaining life basis, as outlined in the Gannett Fleming study filed with the Board on December 3, 2012 and December 17, 2012.

- Provide, at the time of its next depreciation study, a report on group accounting for selected groups of property as outlined in Schedule 1 of P.U. 40 (2012).

During 2012, Hydro reported amortization expense of $47.5 million compared to $43.2 million in 2011 in accordance with the depreciation methodology approved in P.U. 40 (2012). The 2011 amortization was previously reported as $45.7 million. The 2012 amortization includes $46.8 million in depreciation of property, plant, and equipment and $0.7 million in accretion expense related to the asset retirement obligation.

In completing our procedures, we recalculated depreciation using the straight-line methodology on a test basis and compared the estimated average service lives used in the calculations to the Gannett Fleming Depreciation Study approved in P.U. 40 (2012). The recalculation included agreeing the deemed cost of the individual asset selected for examination to the Company's carrying value as at December 31, 2010.

During our review we noted that Holyrood assets not required for synchronous condenser operations were excluded from the Gannet Fleming Depreciation Study. These assets are depreciated using the straight-line method with a remaining useful life of 10 years as Hydro has estimated these assets are expected to be retired in 2020.

Based upon our review and analysis, no discrepancies were noted and, therefore, we report that depreciation expense for 2012 does not appear unreasonable. Nothing has come to our attention to indicate that the amount reported as depreciation is not in accordance with Board Orders.

Non-Regulated Activity

Scope: ***Review Hydro's non-regulated activity and assess the reasonableness of adjustments in the calculation of regulated earnings and review how costs are allocated between regulated and non-regulated operations.***

In P.U.7 (2002-2003), the Board ordered Hydro to file separate financial statements for regulated and non-regulated activities, including reconciliation to annual consolidated financial statements. Included below are the details of the Company's Non-Regulated Statement of Earnings and Retained Earnings for the years ended December 31, 2009 to 2012.

(000)'s	2012	2011	2010	2009
Revenue				
Energy sales	$ 52,275	$ 74,260	$ 83,068	$ 60,687
Other revenue (loss)	59	(1,838)	(2,610)	743
	52,334	72,422	80,458	61,430
Operations and administration				
Net operating	25,645	24,288	25,494	19,758
Foreign exchange loss (gain)	106	(655)	476	-
Fuels	36	36	68	21
Power purchased	7,696	4,569	4,064	4,226
	33,483	28,238	30,102	24,005
Net operating income	18,851	44,184	50,356	37,425
Other revenue				
Equity in CF(L) Co.	18,252	14,890	16,572	7,880
Preferred dividends	10,114	9,588	10,159	3,858
	28,366	24,478	26,731	11,738
Net income	$ 47,217	$ 68,662	$ 77,087	$ 49,163
Retained earnings, beginning of year	$ 356,645	$ 344,828	$ 329,226	$ 324,536
Net income	47,217	68,662	77,087	49,163
Dividends				
Nalcor	(20,170)	(47,257)	(51,326)	(34,949)
CF(L)Co.	(10,114)	(9,588)	(10,159)	(9,524)
Retained earnings, end of year	$ 373,578	$ 356,645	$ 344,828	$ 329,226

Our review of non-regulated operations included the following procedures:

- assessed the Company's compliance with P.U. 7 (2002-2003);
- compared non-regulated expenses and operations for 2012 to prior years and investigated any unusual fluctuations; and
- reviewed detailed listings of expenses for 2012 and investigated any unusual items.

The Company has complied with P.U. 7 (2002-2003) and has filed separate financial statements for both regulatory and non-regulatory operations for 2012. Based on our review, we conclude that Hydro has appropriately identified and defined its various non-regulated operations and has established appropriate procedures for recording and reporting on these activities. Separate business units for the various non-regulated operations within its financial reporting system were used throughout the year.

Based upon our review and analysis, the amounts reported as non-regulated expenses are in compliance with Board Orders, including P.U. 7 (2002-2003) and P.U. 14 (2004).

A summary of the significant non-regulated activity for 2012 is as follows:

- Hydro purchases recall energy from CF(L) Co. and any excess beyond what is required to serve regulated customers in Labrador is available for export sales. In 2012, total revenue from export sales totaled $47.4 million ($69.7 million in 2011). According to Nalcor, the primary reason for the decrease was lower export market electricity prices as a result of decreased demand from historically mild winter weather. Also included in revenue is a $0.1 million gain ($1.8 million loss in 2011) on derivatives used to mitigate the risk of fluctuations in foreign exchange rates as well as commodity prices. In 2012, Nalcor entered into a series of forward foreign exchange contracts to minimize the impact of fluctuations in electricity prices. Nalcor did not enter into any commodity price swaps, as they did in 2011, due to depressed market prices. In 2012 related power purchases increased to $7.7 million from $4.6 million in 2011. According to Nalcor, this increase of 67% was due to increased activity in order to optimize the Quebec transmission asset which resulted in purchases and resale of electricity in export markets at market prices. The net profit from this activity decreased from $43.4 million in 2011 to $16.8 million in 2012.

- The supply of power to the IOCC in 2012 remained relatively consistent in 2012 compared to 2011. Revenues increased to $4.8 million from $4.5 million in 2011 and the net profit from this activity increased from $2.3 million in 2011 to $2.7 million in 2012.

- The increase in net operating expenses of $1.4 million from 2011 is mainly due to an increase in transmission expense of $1.0 million primarily related to a change in transmission rental rates and an increase in professional fees of $1.2 million primarily related to energy marketing and energy optimization fees. This is partially offset by a decrease in miscellaneous and customer costs of $0.9 million primarily relating to a $200,000 credit applied in 2012 to adjust HST and a decrease in bad debts in 2012.

- The decrease in dividends to Nalcor of $27 million from 2011 is primarily due to the decrease in net profit in export sales activity in 2012 as discussed above.

Based upon our review and analysis, nothing has come to our attention to indicate that the amounts reported as non-regulated expenses, as summarized above, are unreasonable or not in accordance with Board Orders.

Cost Allocations

Scope: ***Review how costs are allocated between the regulated and non-regulated operations including a review of Hydro's labour costing relating to its billing rates.***

We reviewed Hydro's methodology relating to the procedures the Company has in place to allocate costs between regulated and non-regulated operations. We also reviewed how costs are allocated between shared services. New billing rates were implemented on April 1, 2012. The rates at April 1, 2012 were increased by 4% compared to April 1, 2011, consistent with the economic increase in salaries.

We also prepared a separate report on Hydro's intercompany transactions over the period 2008-2010 between the regulated business units within Hydro and the other Nalcor entities and lines of business. This report was completed in July 2012.

All non-regulated operations are reported to the Corporate Controller and the Treasurer who ensure that business units, and if applicable, work orders, are set up to track costs. Intercompany salary and benefits charged to and from Nalcor Energy and its subsidiaries are captured in the JD Edwards integrated suite of applications and a Lotus Notes Time Reporting application. These costs are recharged through the cost account '6014 – intercompany salaries' in the appropriate business units.

The following is a summary of non-regulated activities/costs /business units of the Company:

Subsidiaries

- Churchill Falls (Labrador) Corporation– BU#1958. Services from Hydro to CF (L) Co are rendered according to a services agreement dated January 1, 2010. According to the services agreement, all costs are charged according to Hydro's bill rates, fixed charge rate, and an allocation of its intercompany administration fee. This is consistent with Nalcor's intercompany transaction costing methodology. In addition, prior to December 15 each calendar year, Hydro will provide a list of services to be provided, as well as an estimate of costs to be recovered through monthly billing. Billings are adjusted after actual costs for the year have been determined to the satisfaction of both parties.

- Lower Churchill Development Corporation Limited –BU#1953. This corporation is mainly inactive and there were no charges to or from Hydro in 2012.

Business units in Hydro

- Export Sales – BU# 1950. Hydro purchases recall power and energy through an agreement with Churchill Falls. Surplus power is sold by Hydro to external markets. Systems Operations allocates the power purchase costs. All revenue and expenses are captured in Business Unit (BU) 1950 and excluded from regulated income.

- Supply of Power to the Iron Ore Company of Canada – BU# 1952. The portion of costs associated with IOCC is derived from the Cost-of-Service on the Labrador Interconnected system. Rates charged are based on a negotiated contract which is not approved by the Board. All revenues and expenses are captured in BU 1952 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology as discussed above.

- Natuashish – BU# 1405. This business unit was established to track costs associated with the community of Natuashish on behalf of the federal government, on a cost recovery basis. All costs are charged at bill rates plus overheads to ensure full cost recovery. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Menihek – BU#1960. This business unit was established to capture revenues and costs associated with the power purchase agreement with Hydro-Quebec to supply electricity to three communities in Quebec, relating to Hydro's Menihek Generating station.

- Star Lake – BU# 1970. Hydro operates this plant on behalf of Nalcor who is acting as agent of the province. All revenues and expenses associated with this activity are captured in BU 1970 and excluded from regulated expenses. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Ramea Project – BU# 1406. In accordance with P.U. 31 (2007) no costs associated with the project at Ramea will be borne by ratepayers. All revenues and expenses associated with this activity are captured in BU# 1406 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology. Based on our discussion with the Company costs relating to the Ramea Project are not included in rate base.

- Conservation Demand Management – BU# 1949. In accordance with P.U. 8 (2007) Hydro will undertake energy conservation initiatives. All revenues and expenses associated with this activity in Labrador West are captured in BU# 1949 and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology.

- Cost Recovery Business Units. Hydro maintains a number of cost recovery business units to capture costs incurred by Hydro personnel on behalf of other lines of business, e.g. Lower Churchill Project, Oil and Gas, Bull Arm and Nalcor Energy. All costs associated with these activities are billed monthly to the lines of business and excluded from regulated income. Any employee providing services to this activity will charge their time in accordance with Nalcor's intercompany transaction costing methodology. The cost recovery units are as follows:

    a. Lower Churchill Project cost recovery – BU# 1961. Prior to 2008, capital job cost #10250 was set up to capture all costs associated with the current Labrador Hydro Project including an allocation of corporate overhead, salary charges and supplier costs. With the corporate restructuring in 2008, the Lower Churchill project construction work in progress assets were transferred to Nalcor. In 2012, $77,465 (2011 - $264,317) in intercompany salaries were allocated to this project from Hydro.

    b. Oil and Gas cost recovery – BU#1962. This business unit was established to capture costs related to Nalcor's Oil and Gas division which holds and manages oil and gas interests in the Newfoundland and Labrador offshore. In 2012, $107,628 (2011 - $74,485) in intercompany salaries were allocated to this business unit from Hydro.

    c. Bull Arm cost recovery – BU#1963 – This business unit was established to capture costs related to Nalcor's Bull Arm site. In 2012, $26,941 (2011 -$37,915) in intercompany salaries were allocated to this business unit from Hydro.

d. Nalcor Energy cost recovery – BU#1964 – This business unit was established to capture costs related to Hydro costs charged to Nalcor Energy. In 2012, $688,335 (2011 - $865,651) in intercompany salaries were allocated to this business unit from Hydro.

- Other Specific Non-Regulated Costs – BU#1955. This business unit has been established to capture various non-regulated costs, including:
  - Contributions and donations.
  - Advertising for corporate image building.
  - Companion travel costs.
  - Bad debt expenses incurred for specific reasons that are designated non-recoverable are excluded from the determination of regulated income.

Determination of Billing Rates

Bill rates for Hydro and its related companies are determined on a cost recovery basis designed to cover salary, benefits, and vacation. There is no profit margin element to the billing rate. However, charges for external billings do incorporate a profit margin.

According to Hydro, the time sheet policy / guidelines are as follows:

> All Nalcor employees (except CF(L)Co employees) are to prepare weekly time sheets and code all paid hours (i.e. 37.5 or 40 per week) to a work order or to leave. Mandatory and prompt time sheet reporting for all Hydro Place employees was implemented effective Monday, April 19, 2010 (March 2011 outside Hydro Place). Previously, many employees had been required to record exceptional time only (leaves, overtime and charge-out hours). Employees are responsible to record the 37.5 or 40 hour work week, plus any additional overtime and/or premiums. Time sheets are to be completed and submitted no later than the following week.

The billing rates were developed to include a base wage amount (hourly wage), a variable component, and a fixed charge. The Company's billing rate is derived from a base wage amount and a variable component. The fixed charge is a separate charge based on each hour billed.

<u>Variable component</u>
The analysis completed by the Company determined an average variable component over the three year period of approximately 57% of base wage (actual was 58.5% for 2007, 57.9% for 2008, 55.6% for 2009, 59.0% for 2010). The Company used a proxy amount of 57% as the basis to determine bill rates. The following costs were included in the analysis to determine the variable component:

Benefits

- Fringe benefit costs, e.g. CPP, EI, Public Service Pension Plan, Group Money Purchase Plan, Prior Service Matched PSPP, and WHSCC.
- Insurances, e.g. Life, A D&D, Medical, Dental.
- Company costs, e.g. EE future benefits, payroll taxes, bonus, performance contracts, signing bonus.

Leaves

- Annual leave, medical travel and appointments, sick leave, training hours, floaters, family leave, compassion leave, jury duty, statutory holiday, union leave, banked overtime.

<u>Fixed Charge</u>

As discussed above, effective October 1, 2009 the Company included a fixed charge for time charged to entities. The fixed charge was determined to be $80 per day for all Nalcor employees, or $10.67 hour based on a 7.5 hour day. The fixed charge component included the following costs in its analysis:

- *Hydro Place costs* e.g. Heat & Light, insurance, maintenance, reception, depreciation, and interest.
- *Common Services* e.g. IT services such as software, servers & help desk, HR services such as payroll, recruitment, health, safety.
- *Employee related costs* e.g. Telephone & Fax, books & subscriptions, training, membership and dues, conferences, training.

According to Hydro, the fixed charge recovery is booked to account for the additional cost of having an employee available for service beyond salary and benefits. The fixed charge recovers costs originally charged in the administration fee allocation as well as other employee related costs described above. The fixed charge for Hydro is recorded in business unit # 2003 NLH Controller Dept. under Account # 7141 'intercompany fixed charge' and is grouped under cost recoveries. The fixed charges netted to a credit of $346,706 in 2011 and a credit of $233,615 in 2012.

We requested supporting documentation on the analysis prepared by Nalcor to support the proxy percentage of 57% of the variable component as the basis to determine billing rates so we could test for accuracy but it was not provided.

We also selected a sample of employees from the detailed intercompany salary accounts including samples for charges from Nalcor Energy to Hydro and to various business units from Hydro. The selection of samples included both executive and non-executive employees.

Our procedures included:

- Agreeing hours charged to timecards.
- Agreeing the billing rate to the schedule of billing rates provided by Hydro.
- Recalculation of the billing charge in the general ledger as based on the billing rate and hours.
- Assess the reasonableness of the new billing rate(s) applied in comparison to the proxy 57% variable component.

The proxy percentage from the base rate was not expected to be precisely 57% for non-union employees as billing rates were applied to the top of the scale. As a result, the variable component was skewed depending on where the non-union employee was paid within the pay scale. However, we did note one discrepancy in the billing rates for the non-executive employees that were sampled. One employee was being billed using an old bill rate that was based on the previous pay step. All other samples tested were within the expected range of the 57% variable component.

For the executive, we noted certain executive billing rates where there were variations from the expected 57% variable component. According to Hydro, the executive leadership team pay scales fall into one of four groups for operating bill purposes based upon their actual salary. Each grouping is assigned a group dollar value that is representative of the salaries in the grouping. The operating bill rate of 57% is applied to the group dollar value to arrive at an operating bill rate for the group. This process is followed to protect the confidentially of executive leadership salaries. As there are significant differences in executive pay, the variable component percentage varied significantly from the proxy of 57%.

Common Service Costs Allocation

Certain departments based in Hydro provide common services to various lines of business of Nalcor. Hydro recovers costs incurred related to these common services through an administration fee.

The following table provides a summary of the intercompany administration fee and cost recoveries charged in Hydro to Nalcor various lines of business and CF (L) Co. for 2012, 2011 and 2010:

Cost Recoveries	**2012**	**2011**	**2010**	**2012-2011**
Intercompany Administration Fee				
Regulated recovery	**$ (3,680,313)**	$ (1,968,439)	$ (1,537,108)	$ (1,711,874)
Non- regulated expense	**25,152**	11,593	7,669	13,559
	$ (3,655,161)	$ (1,956,846)	$ (1,529,439)	$ (1,698,315)
Cost recovery				
CF (L) Co.	**$ (1,756,218)**	$ (1,475,491)	$ (1,550,963)	$ (280,727)

The primary reason for the increase in the administration fee in 2012 over 2011 of $1,711,874 relates to an increase of $1,041,086 in office space at Hydro Place due to a higher floor space allocation to the other lines of business which increased from 29,298 square feet in 2011 to 66,393 square feet in 2012 [total square footage of Hydro Place is 152,501]. In 2012 the rental rate for Hydro Place increased to $27.40 per square footage compared to $26.56 in 2011. Also contributing to the higher administration fee in 2012 was an increase in information systems of $560,437 which is mainly due to the per user rate increasing from $3,716 per user in 2011 to $4,911 per user in 2012.

The labour costs relating to the staffs that work in the common service business units are not charged to the other entities/lines of business since these costs are included in the administration fee calculation.

The following table provides a breakdown of the 2012 common costs allocated to each line of business, along with 2011 and 2010 allocation of costs:

Common cost allocation	2012	2011	2010	2012 - 2011
Nalcor	$ 1,295,870	$ 650,180	$ 456,438	$ 645,690
Oil and Gas	352,629	181,292	147,420	171,337
BullArm	55,139	39,607	37,015	15,532
Exploits	188,391	134,642	119,442	53,749
Menihek	51,010	27,341	23,868	23,669
Lower Churchill Project	1,712,122	923,784	745,256	788,338
Energy Marketing (Non regulated)	25,152	11,593	7,669	13,559
Subtotal	3,680,313	1,968,439	1,537,108	1,711,874
CF (L) Co.	1,756,218	1,475,491	1,440,735	280,727
Hydro Regulated	8,763,626	8,214,370	6,907,456	549,256
Total common costs allocated	$ 14,200,157	$ 11,658,300	$ 9,885,299	$ 2,541,857

The following table provides a breakdown of costs by department /costs for 2012 and 2011:

	2012				2011	
Department / Costs	Nalcor Entites (Note 1)	CF(L) Co.	Hydro	Total	Nalcor Entites (Note 1)	Variance Nalcor Entities 2012-2011
Human Resources	$ 259,958	$ 376,701	$ 1,050,811	$ 1,687,470	$ 199,188	$ 60,770
Safety and Health	142,300	206,204	575,209	923,713	122,076	20,224
Information Systems	1,336,106	1,173,313	4,481,964	6,991,383	775,669	560,437
Office space and related costs	1,819,181	-	2,359,350	4,178,531	778,016	1,041,165
Telephone and LAN costs	122,768	-	296,292	419,060	93,490	29,278
	$ 3,680,313	$ 1,756,218	$ 8,763,626	$ 14,200,157	$ 1,968,439	$ 1,711,874

Note 1: Nalcor Entities is comprised of Nalcor entities as described in the previous table.

According to Hydro, the department/cost included in the determination of the administrative fee charged, along with the allocation basis, is summarized in the following table:

Department/ Costs	Allocation Basis
Human Resources	FTE
Safety and Health	FTE
Information Systems	Average Users
Office space and related costs	Square footage
Telephone and LAN costs	Average Users

We address each of the departments/costs allocations in turn.

Human Resources

The Human Resources department is responsible for the administration and coordination of all employee related services. Operating costs incurred in providing Human Resources services are allocated to the lines of business based on a per full time equivalent ("FTE") basis. In 2012 the cost per FTE allocated to lines of business for Human Resources was $1,291 per FTE (2011 - $1,290).

Safety and Health

The Safety and Health department is responsible for occupational health services including coordinating corporate efforts with regard to employee safety, wellness, disability and sick leave management, and medical screening. Operating costs incurred in providing Safety and Health services are allocated to the lines of business on a per FTE basis. In 2012 the cost per FTE allocated to lines of business for Safety and Health was $707 per FTE (2011 - $698).

Information Systems

The Information Systems ("IS") department is responsible for providing assistance and support in the areas of Software Applications, Planning and Integration and Business Solutions, maintenance and administration of the corporate wide computer infrastructure and network and provides technical support. Operating costs incurred in providing IS services are allocated to the lines of business on an average user basis. Depreciation expense and a return on rate base at the weighted average cost of capital ("WACC") for costs capitalized such as servers and software are allocated to each line of business on an average user basis. Costs specific to a particular line of business are charged to that line of business and are excluded from the determination of shared costs. In 2012 the cost per user allocated to lines of business for IS was $4,911 per user (2011 - $3,716).

Office Space

Each line of business occupying floor space at Hydro Place is charged a rental charge. The square footage rental rate reflects the average annual capital and operating cost for Hydro Place as determined by the following formula:

> Rental Rate = Hydro Place operating costs + return on rate base + annual depreciation / (divided by) Hydro Place total square footage.

According to Hydro, the cost based rental rate includes the following expenses for Hydro Place:

- Annual depreciation for all common assets.
- System Equipment Maintenance and operating projects.
- Expenses relating to salaries, fringe benefits, group insurance and employee future benefits for Office Services, Building Maintenance, and Transportation.
- Heat & Light.
- Office Supplies.
- Postage.
- Safety Supplies.
- Consulting expenses related to Hydro Place.
- Security Card Maintenance Contract.
- Return on Rate base at WACC for all common assets.

In 2012 the cost per square footage rental rate was $27.40 (2011 - $26.56).

<u>Telephone Infrastructure (PBX) Costs</u>

All lines of business are charged a share of Telephone Infrastructure (PBX) costs including long distance charges. The Local Area Network (LAN) costs provided by Network Services are divided by the total number of LAN ports to derive a cost per user. The telephone costs provided by Network Services are divided by the number of telephone, fax, and modem lines to derive a cost per telephone per user. The average number of users is the factor used for the allocated costs per line of business. For both 2012 and 2011 the cost per user allocated to lines of business for telephone costs was $298 per user and for LAN costs was $198 per user.

The 2012 allocations for Human Resource, Safety and Health, and Information Systems are based on actual costs and would therefore be 'trued up' at year end. However, the PBX and LAN allocations are based on budget costs and there is no 'true up' adjustment on these allocations to reflect actual costs. The office space rental charge would be based on a cost recovery rate set for the year.

In completing our procedures, we requested the Company's supporting calculation of its intercompany administration fees charged to each line of business for 2012. Our procedures included a recalculation of administration fee charged to each line of business based on the allocation basis included in the table above. We did not note any exceptions in our procedures.

As a result of completing our procedures, we noted one exception relating to an employee who was billing using an old bill rate that was based on the previous pay step. Otherwise, we report that cost allocations for 2012 are in accordance with Hydro's methodology

Rate Stabilization Plan ("RSP")

Scope: ***Conduct an examination of the changes to the Rate Stabilization Plan to assess compliance with Board orders.***

Our examination of the RSP for 2012 included reviewing compliance with Board Orders and assessing the charges and credits including financing charges for reasonableness.

The RSP had an accumulated credit balance of approximately $201.7 million at December 31, 2012, which comprises balances of $64.9 million due to the utility customer, $104 million due to industrial customers, and $32.7 million in the hydraulic variation account. A comparative breakdown of the balances in the RSP at December 31, 2012 and 2011 is as follows:

	2012		2011	
Utility Customer	$ (64,905,401)	due to customer	$ (55,939,780)	due to customer
Industrial Customer	(104,079,983)	due to customer	(81,653,349)	due to customer
Sub-total	(168,985,384)		(137,593,129)	
Hydraulic Balance	(32,675,763)		(32,737,147)	
Total Plan Balance	$ (201,661,147)		$ (170,330,276)	

Highlights of the RSP plan for 2012 include:

- For the ninth consecutive year favourable hydraulic conditions contributed to higher hydraulic production relative to the COS production resulting in fuel savings of $10.8 million for 2012 compared to $3.3 million for 2011.

- The average No. 6 fuel price was approximately $59.33 per barrel higher than the COS price of $55.47 per barrel resulting in a fuel variation of approximately $84.6 million due from customers.

- Load variation for industrial customers resulted in savings of $24.6 million. The load variation is primarily the result of a drop in load requirements for industrial customers of 484.7 GWH below the COS compared to a 2011 variance between actual and COS of 583.4 GWh.

It should also be noted that as a result of the appeal of P.U. 25 (2010), which is discussed later in this report, the disposition of the load variation is one of the issues to be considered by the Board in a future hearing.

The fuel price rider was established to adjust RSP rates for anticipated forecast fuel price changes. During 2012, the RSP adjustment for the utility customer, which includes the fuel price rider, resulted in $64.5 million in recoveries. The RSP adjustment rate for the industrial customers resulted in $4.1 million in refunds to industrial customers. The RSP adjustment rate for the industrial customers does not include a fuel price rider since this rate was originally set as a result of the 2007 test year and has been an interim rate since that time. The RSP adjustment rate for the utility was 0.931 cents per kWh effective July 1, 2011 to June 30, 2012 and 1.555 cents per kWh effective July 1, 2012. The RSP adjustment rate for industrial customers, excluding Teck Cominco Limited, was 0.785 cents per kWh. Teck Cominco Limited and Vale Newfoundland & Labrador Limited rate was 2.000 cents per kWh as they were excluded from the historical plan, in accordance with P.U. 1 (2007) and P.U. 6 (2012), respectively. Rates related to RSP adjustments for Teck Cominco Limited and Vale Newfoundland &

Labrador Limited as well as the other industrial customers are based on interim rates from 2007 and have not been finalized.

The tables below provide a breakdown of the activity in the RSP for 2012 as well as a continuity of the various component balances.

(000)'s	Hydraulic Variation	Fuel Variation	Load Variation	Rural rate Alteration	Total
Hydraulic balance	$ (10,831)				$ (10,831)
Industrial customers		$ 5,576	$ (24,548)	-	$ (18,972)
Utility customers		78,355	(97)	$ (6,271)	$ 71,987
Labrador Interconnected	112				112
Net change 2012	$ (10,719)	$ 83,931	$ (24,645)	$ (6,271)	$ 42,296

(000)'s	Balance Beginning of Year	Current Variation	Current Interest	Hydraulic Allocation	Refund (Recovery)	Payment	Net Change	Balance End of Year
Hydraulic variation balance	$ (32,737)	$ (10,831)	$ (3,404)	$ 14,296			$ 61	$ (32,676)
Industrial customers	(81,654)	(18,972)	(6,602)	(942)	$ 4,090		$ (22,426)	$ (104,080)
Utility customers	(55,939)	71,987	(3,182)	(13,242)	(64,529)		$ (8,966)	$ (64,905)
Labrador Interconnected [1]	-	112		(112)			$ -	$ -
Net change	$ (170,330)	$ 42,296	$ (13,188)	$ -	$ (60,439)	$ -	$ (31,331)	$ (201,661)

[1] The amount is written off to net income.

As noted in previous annual review reports, on June 30, 2009, Hydro filed an Application with the Board concerning the RSP rates to be charged to Industrial Customers and its analysis of the fuel and load variation caused by the events in the pulp and paper industry. In its Application, Hydro indicated that it had updated and completed its analysis of the fuel and load variance caused by the events in the pulp and paper industry and that the application of the existing RSP rules to calculate rates for Industrial Customers would result in significant and unreasonable rate volatility. Therefore, in this Application, Hydro proposed that the rates for Teck Cominco Limited be the same as those in effect for the other Island Industrial Customers and that the existing interim rates currently in effect for these customers are made final.

There was a preliminary hearing regarding this Application held on June 14, 2010 with Hydro and the various interveners present. The preliminary hearing was held to receive submissions from the parties on the question of whether the Board had the jurisdiction to change the manner in which the RSP operated, including the rates charged, the determination of the balance(s) in the RSP and how these balances are allocated to customer classes. On August 26, 2010, the Board issued P.U.25 (2010) which addressed its decision arising from the preliminary hearing. The Board's conclusion was as follows:

"The Board finds that in the circumstances its jurisdiction to make orders in relation to how the RSP operated in prior years is limited. Given the manner in which this matter was brought forward the Board does not have the jurisdiction to change how Newfoundland Power's RSP operated in prior years, either in terms of the rates charged or the resulting

balances. The Board does have the jurisdiction to issue an order which sets just and reasonable rates for the Industrial Customers for 2008 and 2009, including the Industrial Customers' RSP rates and how the Industrial Customers RSP operated for these years. The Board also finds that it has jurisdiction to determine whether any overpayment as a result of the interim rates is to be refunded to the Industrial Customer group or placed in a reserve account to the benefit of the Industrial Customer group…."

As a result of this Decision of the Board, an appeal was filed by Hydro and the Consumer Advocate. The Supreme Court of Newfoundland and Labrador, Court of Appeal released its decision on this matter on June 19, 2012.

The Court allowed the appeal and indicated in its decision that the Board's decision in declining jurisdiction was incorrect.

In the Court's conclusion in its decision, paragraph 157, page 47, the Court stated the following:

"We conclude that the Board has jurisdiction to deal with and dispose of remaining amounts in the RSP in accordance with the broad powers contained in the legislation, which include , but are not limited to, refunding it to the Industrial Customers. But these powers are not necessarily confined to disposing of the RSP fund balances solely to the benefit of one class of customers, in this case the Industrial Customers. This is not to say, of course, that the Board should include customers other than the Industrial Customers as beneficiaries, only that the Board has the jurisdiction and authority to, and should, consider the submissions of all interested parties on this issue, taking into account generally accepted sound public utility practice and the imperative of setting just and reasonable rates that are non-discriminatory."

According to the Court of Appeal, this matter is now back to the Board for hearing and determination on the merits in accordance with the decision.

Since issuing P.U. 25 (2010), the Board has issued P.U. 10 (2011) and P.U. 15 (2012). In these Orders, the Board ordered that the RSP rates to be charged to Newfoundland Power that were effective July 1, 2011 and July 1, 2012, are approved on an interim basis.

Also, during 2012 the Board issued P.U. 6 (2012). This Order related to an application filed by Hydro for the approval of certain rules and regulations pertaining to the supply of electrical power and energy to one of its industrial customers, Vale Newfoundland & Labrador Limited ("Vale"). In its Order the Board approved the Service Agreement. However, the Board ordered that Hydro apply the interim rates that are applicable to Teck Resources Limited effective from the date that Vale first begins receiving power under the approved Service Agreement.

In the Order the Board noted the following:

"The Board notes that, at present, neither of the existing interim Industrial rates recovers the cost of providing service. There is also no proposed rate before the Board which is a true cost-based rate. The Board is satisfied that the Teck Resources rate would be most representative of the conditions under which Hydro will be providing service to Vale, as this rate was established under similar circumstances. The Board will make no determination at this time with respect to the participation of Vale in the RSP, except in respect of the interim rate approval herein."

Based upon our review, we report that the RSP is operating in accordance with Board Orders and the charges and credits made to the Plan in 2012 are supported by Hydro's documentation and accurately calculated.

Deferred Charges

Scope: ***Conduct an examination of the changes to deferred charges and assess their reasonableness and prudence in relation to sales of power and energy.***

The following table shows the transactions in the deferred charges account for 2009 to 2012:

	Balance Jan 1/12	Add. (Disp)	Amort.	Balance Dec 31/12	Balance Dec 31/11	Balance Dec 31/10	Balance Dec 31/09
Realized foreign exchange losses	$64,708	-	($2,157)	**$62,551**	$64,708	$66,865	$69,022
Asbestos abatement	605	-	(605)	**-**	605	1,948	4,080
Boiler	-	-	-	**-**	-	302	752
Study costs	-	-	-	**-**	-	50	100
Conservation Demand Program	1,045	1,385	-	**2,430**	1,045	571	159
	$66,358	1,385	($2,762)	**$64,981**	$66,358	$69,736	$74,113

The following table summarizes the actual versus budgeted Conservation Demand Program expenditures for the past four years from 2009 to 2012.

	2012	2011	2010	2009	Total
Actual	$ 1,385,000	$ 474,000	$ 412,000	$ 159,000	**$ 2,430,000**
Budget	1,673,000	840,000	2,300,000	1,800,000	**6,613,000**
Under Budget	$ (288,000)	$ (366,000)	$ (1,888,000)	$(1,641,000)	**$(4,183,000)**
% Under Budget	**(17%)**	**(44%)**	**(82%)**	**(91%)**	**(63%)**

Pursuant to P.U. 14 (2009) Hydro received approval to defer Conservation Demand Management Program costs ("CDM") estimated to be $1.8 million. Amortization of the deferred costs will be subject to a further order of the Board. In 2009 CDM costs of $159,000 were deferred in relation to the energy conservation program for residential, industrial, and commercial sectors relating to the delivery of the takeCHARGE Rebate programs. According to the Company, costs associated with general awareness, planning functions and partnership programs and initiatives that would be incurred regardless of the specific rebate programs currently being offered were expensed. The variance of $1.6 million from actual CDM costs and estimated costs of $1.8 million was primarily due to a delay in the launch of the Industrial program. The industrial program had a budget of $1.5 million but only $57,000 was spent and deferred in 2009.

Pursuant to P.U. 13 (2010) Hydro received approval to defer 2010 costs related to the CMD Plan. These costs were estimated to be $2,300,000. Actual costs deferred in 2010 were $412,000. Total costs summarized in the December 31, 2010 quarterly regulatory report were $500,000 in Section 3.3.6. According to Hydro, the difference of $88,000 was related to non-regulated customers and not put through the deferral account. The majority of the 2010 variance between estimated costs and actual CDM costs continues to be the Industrial Energy Efficiency Program and the delays in getting this program up and running. The Industrial program had a budget of $2.0 million for 2010 but only $200,000 was spent and deferred.

Pursuant to P.U. 4 (2011) Hydro received approval to defer 2011 costs related to the CDM Plan estimated at $840,000. The majority of the 2011 variance between estimated costs and actual CDM costs continues to be the Industrial Energy Efficiency Program and lack of participation. The Industrial program had a budget of $564,000 for 2011 but only $98,000 was spent and deferred.

Pursuant to P.U. 3 (2012) Hydro received approval to defer 2012 costs related to the CDM Plan estimated at $1,673,000. The majority of the variance between estimated costs and actual CDM costs in 2012 relates to the Industrial expansion programs. The Industrial program continues to experience a lack of customer participation and as a result only $170,000 of the estimated $465,000 was spent and deferred in 2012.

Based upon our analysis, nothing has come to our attention to indicate that changes in deferred charges for 2012 are unreasonable. However, we do note that there have been significant variances between estimated and actual costs related to the Conservation Plan in 2009, 2010, 2011 and 2012. In all years the Company spent significantly less than expected and we recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the budgeting process and to address the apparent lack of participation in the Conservation Demand Management Program as compared to budget.

Key Performance Indicators and Initiatives and Efforts Targeting Productivity and Efficiency Improvements

Scope: ***Review Hydro's Annual Report on Key Performance Indicators and any other information on initiatives and efforts targeting productivity or efficiency improvements in 2012.***

In P.U. 14 (2004) Hydro was ordered to file annually with the Board a report outlining:

i. a strategic overview highlighting core strategies, corporate goals and achievements;
ii. appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes/measures, including certain specified KPI's; and
iii. initiatives targeting productivity or efficiency improvements, including the status of ongoing projects and improved performance resulting from completed projects.

The 2012 annual report on strategic goals and objectives and productivity initiatives was filed with Hydro's December 31, 2012 quarterly report on February 14, 2013. Data in the financial section of the Annual Report on Key Performance Indicators was not available at the time of the original filing. This information was subsequently filed on June 14, 2013.

In addition to the filing requirements identified above, P.U. 14 (2009) requires the filing of a report on Hydro's Conservation and Demand Management activities. This report is included as Return 21 in the 2012 annual financial return.

Strategic Goals and Objectives

The quarterly report referenced above provides information on Hydro's achievements relative to its 2012 strategies, goals and initiatives. This section provides details on activities and outcomes relative to a broad range of initiatives undertaken during the 2012 fiscal year.

Details on the three goals discussed in the report are presented below:

<u>To be a Safety Leader</u>

Hydro notes that it continues its commitment to being a world class leader in safety performance in 2012. To track their performance on this objective Hydro continued to monitor All Injury Frequency, Lost Time Injury Frequency, the ratio of condition and incident reports to lost time and medical treatment injuries and the progress towards developing work methods for critical tasks. In addition, in 2012 Hydro completed an audit work protection code compliance process.

The results of these metrics have been presented in the table below.

Measurement	Year-to-date 2012 Actual	Annual 2012 Plan	Annual 2011 Actual	Target Met
All Injury Frequency (AIF)	2.25	<0.8	0.91	No
Lost Time Injury Frequency (LTIF)	0.79	<0.2	0.13	No
Ratio of condition and incident reports to lost time and medical treatment injuries (lead/lag ratio)	230:1	600:1	578:1	No
Audit Work Protection Code Compliance	Completed			N/A
Complete Work Method Development for Critical Tasks	87.33%	85%[1]	N/A	Yes

1 – In the December 31, 2012 quarterly report Hydro indicated that the year-to-date 2011 actual results for work method development were incorrectly reported at 100%. The annual 2012 plan was 85%. During our review of minutes from the Hydro Leadership Team meetings it was noted that this project was on going throughout 2012.

Three out of the five of Hydro's safety targets were not met in 2012. However, Hydro has indicated, in the December 31, 2012 quarterly report, that the injuries were preventable and mainly low risk in nature. As well, in 2013 Hydro has indicated they are committed to continue to apply a targeted approach to injury prevention, communication, and awareness with support for this objective visible at all levels within the organization. To further place emphasis on this objective Hydro has stated that it will also focus on supporting and recognizing those areas that demonstrate exceptional safety performance.

<u>To be an Environmental Leader</u>

Hydro notes that it recognizes its commitment and responsibility to protect the environment. Targets used to evaluate this goal are summarized below.

Measurement	Year-to-Date 2012 Actual	Annual 2012 Target	Annual 2011 Actual	Target Met
Achievement of EMS targets	96%	95%	91%	Yes
Variance from ideal production schedule at Holyrood Thermal Generating Station	6.9%	<= 11.0%	9.8%	Yes
Annual energy savings from Residential and Commercial Conservation and Demand Management Programs	2.6GWh	3.4GWh	1.1GWh[1]	No
Annual energy savings from Industrial Conservation and Demand Management Programs	3.2GWh	6.6GWh	0.2GWh[1]	No
Annual energy savings from Internal Energy Efficiency Programs	0.26GWh	0.15GWh	0.17GWh[1]	Yes

1 – During 2012, Hydro adopted a revised reporting methodology which focuses on new annual savings. In the December 31, 2011 quarterly regulated report these balances were grouped with non-takeCHARGE programs and outreach programs to provide a cumulative total of energy savings since the beginning of the various programs. The 2011 comparative figures presented were revised to reflect the new annual savings reporting.

The measurement of annual energy savings from Residential and Commercial Conservation and Demand Management Program did not meet the 2012 target. The savings were lower than expected due to a number of factors, including lower uptake in the components outside the direct installation initiative, as well as lower than expected savings in the first months of operation of the Isolated Systems Business Efficiency Program. Also, savings for the initial activities through the Block Heater Timer program are not included as quality assurance is required to verify them.

The measurement of annual energy savings from Industrial Conservation and Demand Management Program did not meet the 2012 target. While the target was not met, Hydro has indicated that three programs were completed through the Industrial Program. These projects differ in size and savings. Hydro has also pointed out that there are other projects in various stages of feasibility research and review with economically viable projects moving to the implementation stage.

<u>Through Operational Excellence Provide Exceptional Value to all Consumers of Energy</u>

In 2012 Hydro focused on three areas: energy supply, asset management, and financial performance. Targets used to evaluate these objectives are summarized below.

Measurement	Year-to-Date 2012 Actual	Annual 2012 Target	Annual 2011 Actual	Target Met
Asset Management and Reliability				
Winter Availability	99.97%	>98.0%	98.3%	Yes
Asset Management Strategy Execution Plan Implemented	Completed Targets	N/A	N/A	N/A
Financial Targets				
Annual Controllable Costs	-1.7%	Budget	-3.2%	Yes
Net Income	$16.9 million	$15.3 million	$20.6 million	Yes
Return on Capital Employed	7.2%	7.3%	7.9%	No
Project Execution				
Completion rate of capital projects by year end	82%	>94%	83%	No
All-project variance from original budget	18%	8%	5%	No
Customer Service				
Rural Residential Customer Satisfaction rate	80%	>90%	88%	No

In 2012, Hydro did not meet the target set for return on capital employed, completion rate of capital projects by year end, all project variance from original budget, and the rural residential customer satisfaction rate.

Key Performance Indicators

Appendix E to the December 31, 2012 quarterly report filed by Hydro includes the 2012 Annual Report on Key Performance Indicators. This version did not include financial data pending the completion of the audited financial statements. Hydro subsequently filed an updated version of the 2012 Annual Report on Key Performance Indicators ("KPI") on June 14, 2013. The KPI results for 2012 as compared with prior years are summarized in the table on the next page:

Category/KPI	Measure Definition	Units	2008	2009	2010	2011	Avg. 08-11	2012	Variance from Average
Reliability									
Generation									
Weighted Capability Factor[2]	Availability of Units for Supply	%	83.2	82.0	85.1	83.3	83.4	82.90	(0.5)
Weighted DAFOR[2]	Unavailability of Units due to Forced Outage	%	4.97	4.50	1.80	2.70	3.49	2.30	(1.19)
Transmission[6]									
SAIDI	Outage Duration per Delivery Point	Minutes / Point	278.0	100.3	173.5	432.0	246.0	171.0	(75.0)
SAIFI	Number of Outages per Delivery Point	Number / Point	1.69	0.90	2.30	4.50	2.35	1.90	(0.45)
SARI	Outage Duration per Interruption	Minutes / Outage	164.0	111.4	75.0	96.0	111.6	90.0	(21.6)
Distribution									
SAIDI	Average Outage Duration for Customers	Hours / Customer	11.2	9.4	6.4	16.3	10.8	8.3	(2.5)
SAIFI	Number of Outages for Customers	Number / Customer	6.3	4.3	3.5	5.7	5.0	4.4	(0.6)
Under Frequency Load Shedding									
UFLS	Customer Load Interruptions Due to Generator Trip	Number of Events	6	7	6	3	6	5	(1)
Operating									
Hydraulic Conversion Factor[3]	Net Generation / 1 Million m^3 Water	GWh / MCM	0.433	0.436	0.436	0.434	0.435	0.434	(0.001)
Thermal Conversion Factor[4]	Net kWh / Barrel No. 6 HFO	kWh / BBL	625	612	589	603	607	599	(8)
Financial (Regulated)									
Controllable Unit Cost[5]	Controllable OM&A$ / Energy Deliveries	$ / MWh	$14.05	$14.91	$14.25	$14.96	$14.54	$14.93	$0.39
Generation Controllable Costs	Generation OM&A$ / Installed MW	$ / MW	$26,217	$26,138	$25,465	$26,169	$25,997	$25,131	($866)
	Generation OM&A$ / New Generation	$ / GWh	$7,362	$8,267	$8,159	$7,833	$7,905	$7,358	($547)
Transmission Controllable Costs	Transmission OM&A$ / 230 kV Eqv Circuit	$ / Km	$4,023	$3,870	$4,021	$4,275	$4,047	$4,335	$288
Distribution Controllable Costs	Distribution OM&A$ / Circuit Km	$ / Km	$2,305	$2,429	$2,755	$2,934	$2,606	$2,960	$354
Other									
Percent Satisfied Customers	Satisfaction Rating	Max = 100%	89%	91%[1]	92%	91%	91%	80%	-11%

Notes:
1. Historical data has been updated and/or corrected where applicable.
2. The 2012 targets for weighted capability factor and DAFOR are based on the annual generation outage schedule.
3. For the Bay d'Espoir hydroelectric plant.
4. For Holyrood thermal plant.
5. Energy deliveries have been normalized for weather, customer hydrology, and industrial strikes. No adjustments have been made for Abitibi-Consolidated Stephenville mill closure.
6. The 2012 targets for T-SAIFI and T-SAIDI are based on the combination of forced and planned outage performance.

Consistent with prior years, Hydro reports on 16 KPI's covering the following four areas: reliability, operating, financial and customer related.

Category	KPI	Units	2012 Target	2012 Results	Target Achieved
Reliability	Weighted Capability Factor (WCF)	%	84.9	82.9	No
	Weighted DAFOR	%	2.7	2.3	Yes
	T-SAIDI	Minutes / Point	265[1]	171[2]	Yes
	T-SAIFI	Number / Point	2.0[1]	1.9[2]	Yes
	T-SARI	Minutes / Outage	133[1]	90[2]	Yes
	D-SAIDI	Hours / Customer	5.9	8.3	No
	D-SAIFI	Number / Customer	3.7	4.4	No
	Underfrequency Load Shedding	# of events	6	5	Yes
Operating	Hydraulic CF	GWh / MCM	0.433	0.434	Yes
	Thermal CF	kWh / BBL	630	599	No
Financial [3]	Controllable Unit Cost	$/MWh	N/A	$14.93	N/A
	Generation Controllable Costs	$/MW	N/A	$25,131	N/A
	Generation Output Controllable Cost	$/GWh	N/A	$7,358	N/A
	Transmission Controllable Cost	$/Km	N/A	$4,335	N/A
	Distribution Controllable Cost	$/Km	N/A	$2,960	N/A
Other	Customer Satisfaction (Residential)	Max = 100%	>90%	80%	No

1-Transmission reliability targets were set on combined planned and unplanned outages.
2-The transmission reliability indicator shown is for planned and unplanned outages.
3-Targets are only set for financial KPI"s during a test year therefore, no financial targets were set in 2012.

Several of the targeted KPI's set by Hydro were not met in 2012. Within the reliability category the targeted weighted capability factor for 2012 was 84.9%. Hydro did not meet this target as the actual results showed a WCF factor of 82.9% in 2012. The targeted distribution system average interruption duration index (SAIDI) was 5.90 hours per customer. Actual results reflected a rate of 8.25 hours per customer. The actual result did not meet the target set, however it did show improvement over the 2011 actual rate of 16.32 hours per customer. Finally, the targeted distribution system average interruption frequency index (SAIFI) rate of 3.7 interruptions per customer was not met. The actual SAIFI rate for 2012 was 4.4 interruptions per customer. Again, while the target in this area was not met the 2012 results show improvement as the SAIFI rate was decreased from 5.70 interruptions experienced per customer in 2011.

Within the operating category Hydro achieved a net thermal conversion factor of 599kWH per barrel, which is below the 2012 target of 630kWh per barrel. According to Hydro, this reduction is primarily related to operating the plant at lower generating levels due to high volume of water resources and energy receipts relative to the system load requirements. The experience in 2012 declined from the 2011 results of 603kWh per barrel.

Finally, in 2012 the residential customer satisfaction survey shows that 80% of customers are either very satisfied or somewhat satisfied with Hydro. This is a decrease both from the residential customer satisfaction achieved in 2011 (88%) and the 2012 target of >= 90%. According to Hydro, customer satisfaction with the reliability of service appears to be the indicator for this decline in performance in this area.

We have reviewed the KPI results and the explanations provided by Hydro for the changes and variations experienced in 2012 and find them to be consistent with our observations and findings noted in conducting our annual financial review. There were no internal inconsistencies identified in Hydro's report.

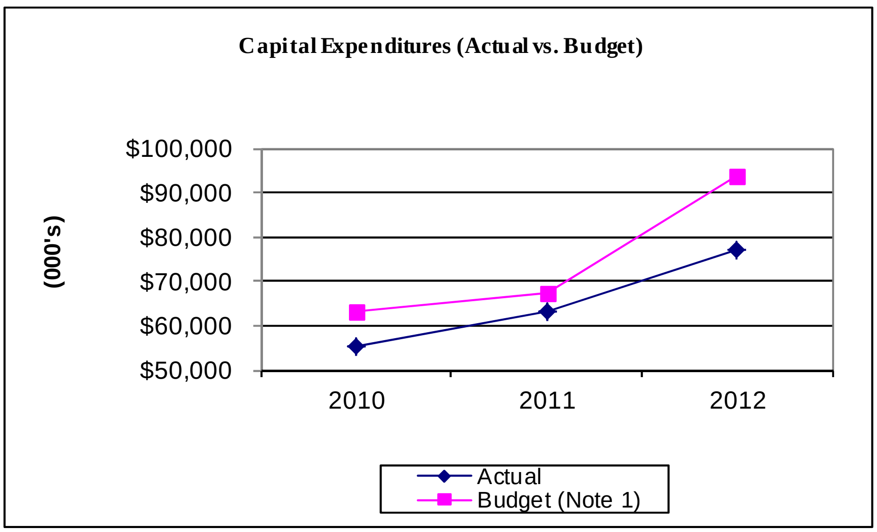
We believe the annual reporting by Hydro of its strategic goals and objectives and its KPI's is useful and of value to the Board in evaluating the financial and reliability performances of Hydro. However, we believe improvements to the reporting can be made. KPI targets are most useful when they are set during the budgeting process as they should guide the Company's operations in the coming year. As such, we believe the targets for the upcoming year should be made available when the Company reports its KPIs. In addition, while the Company has noted that it only sets financial KPI targets in a test year, we believe setting these targets on an annual basis, regardless of whether or not it is a test year, would provide useful information on how actual performance is tracking compared to targets.

Capital Expenditures

Scope: ***Review the Company's 2012 capital expenditures in comparison to budgets and follow up on any significant variances.***

The following table details the actual versus budgeted capital expenditures for the past three years from 2010 to 2012.

(000's)	**2010**	**2011**	**2012**
Actual	**$ 55,553**	**$ 63,116**	**$ 77,252**
Budget (Note 1)	**$ 63,297**	**$ 67,454**	**$ 93,840**
Under Budget	**(12.23%)**	**(6.43%)**	**(17.68%)**



Note 1: The 2012 budget consists of the following: capital budget approved under P.U. 2 and 5 (2012) - $76,992,000; new projects approved under P.U. 24 (2012) - $492,000; new projects approved under P.U. 25 (2012) - $2,941,000; new projects approved under P.U. 26 (2012) - $321,000; new projects approved under P.U. 27 (2012) - $3,155,000; new projects approved under P.U. 35 (2012) - $10,000; projects carried forward to 2012 - $9,756,000; new projects under $50,000 approved by Hydro - $173,000.

The above graph demonstrates that from 2010 to 2012 the Company has been under budget (ranging from 6.43% to 17.68%) on its capital expenditures for the past three years.

Capital Budget Guidelines Policy

The Company is required to follow Capital Budget Guidelines Policy number 1900.6. Within these guidelines the Company must apply for approval of supplemental capital budget expenditures and file an annual capital expenditure report by March 1st of the following year explaining variances of both $100,000 and 10% from budget. Included in the Company's 'Capital Expenditures and Carryover Report' dated March 2013, the Company has provided explanations for variances on 40 projects. We confirm that the Company is in compliance with this guideline.

Guideline 1900.0 also requires that the Company provide a summary of the actual versus budget variance for the past 10 years and "should the overall variance in any two years exceed 10% of the budgeted total the report should address whether there should be changes to the forecasting or capital budgeting process which should be considered".

In the Company's 'Capital Expenditures and Carryover Report' the required schedule was provided which compared budget versus actual expenditures for 2003 to 2012. During each year of this 10 year period the Company has been under budget (ranging from a 6.4% variance in 2011 to a 28.9% variance in 2005). The average percent variance during this 10 year period is 14.54%.

The Company has noted that over the 10 year period the annual variance between budget and actual capital expenditures is almost entirely due to under-spending as a result of not completing all projects approved each year. The Company attributes this to both unavoidable delays due to factors such as system constraints which are precipitated by changes in hydrology, equipment failures, etc. There are also cost increases and project delays being experienced due to the strong labour market. Hydro has noted that it is working to address these issues by reviewing its packaging of projects to encourage competitive bids, as well as attracting additional bidders.

We recommend that the Board consider requesting an update from Hydro as to actions taken by the Company to improve the accuracy of its capital budgeting process. As noted above, the actual budget variance for 2012 was 17.68%.

A breakdown of the total capital expenditures and budget for 2012 with variances by asset category is as follows:

(000's)	2012 Actual	2012 Budget	Variance	%
Generation	**$ 16,129**	$ 30,375	$ (14,246)	(46.90%)
Transmission and Rural Operations	**42,556**	40,467	2,089	5.16%
General Properties	**7,240**	8,045	(805)	(10.01%)
Major Overhauls and Inspections	**6,562**	6,840	(278)	(4.06%)
Allowance for Unforseen Events	**1,374**	1,000	374	37.40%
Additional Projects Approved by P.U.B.	**3,231**	6,919	(3,688)	(53.30%)
New Projects Approved under $50,000	**161**	196	(35)	(17.86%)
Total	**$ 77,253**	$ 93,842	$ (16,589)	(17.68%)

As indicated in the table, capital expenditures are under the approved budget by $16,589,000 (17.68%). This budgeted amount includes the approved capital budget of $84,086,000 and carryovers from 2011 to 2012 of $9,756,000. There is a difference of $673,000 between the actual amount carried over from 2011 and the budgeted amount ($9,083,000) per the 2011 Capital Expenditures and Carryover Report. During 2012, Hydro adopted new accounting policies as approved by the Board in order P.U. 13 (2012). Once the Board order was issued, actual expenditures were adjusted to reflect the change in policy while approved budgeted numbers were not. This resulted in the $673,000 variance. The Company has reported that there are 43 projects which were included in the 2012 budget which have expenditures totaling $19,500,900 carried forward to 2013.

In previous years, Hydro's 'Capital Expenditures and Carryover Report' analysed the Company's capital budgeting process by calculating the variance between budgeted expenditures and actual expenditures for the current year. In 2012, the format of the report changed in order to disclose actual and budgeted past expenditures, as well as actual and budgeted forecasted expenditures for each project. A breakdown of these expenditures with variances by category is as follows:

(000's)	Budget				Actual				Variance	
	Up to 2011	2012	Forecast	Total	Up to 2011	2012	Forecast	Total	$	%
Generation										
Hydro Plants	$ 1,743	$ 9,961	$ 1,502	$ 13,206	$ 1,119	$ 4,912	$ 7,875	$ 13,906	$ (700)	-5%
Thermal Plants	7,293	11,586	1,698	20,577	5,081	10,598	6,044	21,723	(1,146)	-6%
Gas Turbines	2,275	4,280	-	6,555	2,395	619	4,287	7,301	(746)	-11%
Total Generation	11,311	25,827	3,200	40,338	8,595	16,129	18,206	42,930	(2,592)	-6%
Transmission and Rural										
Terminal Stations	11,953	10,857	1,290	24,100	9,434	15,785	1,867	27,086	(2,986)	-12%
Transmission Lines	289	2,884	880	4,053	448	2,864	783	4,095	(42)	-1%
Distribution	8,786	17,416	2,677	28,879	6,834	20,591	3,720	31,145	(2,266)	-8%
Generation	1,289	1,191	1,206	3,686	579	680	2,343	3,602	84	2%
Properties	79	566	-	645	4	596	-	600	45	7%
Metering	292	628	288	1,208	228	705	269	1,202	6	1%
Tools and Equipment	1,251	2,019	396	3,666	986	1,334	897	3,217	449	12%
Total Transmission and Rural	23,939	35,561	6,737	66,237	18,513	42,555	9,879	70,947	(4,710)	-7%
General Properties										
Information Systems	998	2,347	388	3,733	955	2,417	308	3,680	53	1%
Telecontrol	1,350	2,686	-	4,036	1,850	2,261	-	4,111	(75)	-2%
Transportation	2,351	2,350	1,219	5,920	1,254	2,350	1,336	4,940	980	17%
Adminstrative	-	381	-	381	-	212	-	212	169	44%
Total General Properties	4,699	7,764	1,607	14,070	4,059	7,240	1,644	12,943	1,127	8%
Major Overhauls and Inspections	-	6,840	-	6,840	-	6,562	651	7,213	(373)	-5%
Allowance for Unforeseen Events	-	1,000	-	1,000	-	1,374	-	1,374	(374)	-37%
Additional Projects Approved	-	6,919	3,737	10,656	-	3,231	5,405	8,636	2,020	19%
New Projects Approved under $50,000	23	173	-	196	-	162	-	162	34	17%
Total	$39,972	$84,084	$15,281	$139,337	$31,167	$77,253	$35,785	$144,205	$ (4,868)	-3%

The largest variances relate to the following asset classes: generation ($2,592,000 over budget), transmission, and rural ($4,710,000 over budget), general properties ($1,127,000 under budget), and additional projects approved by the Board ($2,020,000 under budget). As discussed earlier in this report, the Company has provided detailed explanations on budget to actual variances in its 'Capital Expenditures and Carryover Report'. For a complete review of the budget variance we refer the reader to the Company's 'Capital Expenditures and Carryover Report'.

Allowance for Unforeseen Events

During 2012 the Company incurred costs related to the Black Tickle Fire Restoration Project which was under the category 'Allowance for Unforeseen Events'. This asset category has an allowance amount of $1,000,000. Actual costs incurred by Hydro were $1,544,872. In addition, Hydro recorded a recovery of costs related to insurance proceeds that was applied against this project in the amount of $170,472.

Guideline 1900.6 sets out the requirements that Hydro must follow regarding these expenditures. These include the following:

- "Before proceeding with work using the Allowance for Unforeseen Items account, or as soon as practical thereafter, the utility must notify the Board in writing that it intends to proceed with an expenditure greater than $50,000 without the approval of the Board using the Allowance for Unforeseen Items account. This notice must set out the detailed circumstances, including the justification for the expenditure and the reason for the use of the Allowance for Unforeseen Items account, providing to the extent available at the time, a scope and costing for the expenditure"

- "Within 30 days after the completion of the work the utility shall file a detailed report setting out:
    i. the circumstances of the expenditure;
    ii. any reliability or safety issues;
    iii. why the work was not anticipated in the annual capital budget;
    iv. the alternatives considered;
    v. the financial effects of each alternative and the reasons for the chosen alternative;
    vi. a timeline setting out all relevant dates;
    vii. the nature and scope of the work;
    viii. the detailed costs incurred; and
    ix. any other implications for other aspects of the utility business/systems.

From our review of the 'Allowance for Unforeseen Events' we note the following:

- On March 14, 2012, the community of Black Tickle experienced a power outage as a result of a fire at the diesel plant. The plant experienced significant damage and required emergency restoration efforts to re-establish power to the community.
- Hydro did not receive Board approval prior to using the 'Allowance for Unforeseen Items' account because restoring power to the community was urgent in nature and according to the Company delaying restoration until Board approval was obtained would have resulted in prolonged customer outages.
- Hydro filed a Power Outage and Incident Advisory Form to the Board on March 14, 2012. This form outlined the circumstances of the unforeseen event and the actions taken by Hydro to temporarily repair the diesel plant and restore power. This form was acknowledged and accepted by the Board on March 21, 2012.
- In September of 2012, Hydro filed a report to the Board regarding the use of the 'Allowance for Unforeseen Items' account for the Black Tickle Diesel Fire Restoration Project. Included in this report was a description of the background and purpose of the project, the nature, and scope of the work completed on the project thus far, a timeline setting out all relevant project dates, and an estimation of the total costs to be incurred upon completion of the project in early 2013.
- On January 3, 2013, the Board wrote a letter to Hydro requesting that the company file a detailed report in relation to the Black Tickle fire restoration project on or before April 1, 2013. Upon receipt of this report, the Board would advise as to how this matter would proceed. In April 2013, Hydro filed a report to the Board in response to this letter.
- As at December 31, 2012, the total costs incurred were $1,544,872, along with a recovery of costs of $170,472. This is $374,400 more than the available allowance of $1,000,000 for unforeseen events. The scheduled date of completion of the project is August 2013.
- Hydro included the capital costs associated with these projects in its 2012 rate base.

As a result of the events outlined above, the expenditures relating to the Black Tickle Diesel Fire Restoration Project require further review by the Board before being added to the rate base.

Board Order P.U.1 (2010)

In P.U. 1 (2010) the Board approved a capital expenditure of $1,550,000 for the project "Upgrade Plant Access Road Bay d'Espoir". In its Order, the Board noted that "Hydro will not be permitted to reflect this expenditure in rate base until it has satisfied the Board that the inclusion of these costs in rate base is consistent with generally accepted sound public utility practice". In Hydro's application filed August 12, 2011 it sought approval for $600,000 relating to the "Upgrade Plant Access Road Bay d'Espoir" project. In P.U. 23 (2011) the Board denied the application for the costs to be included in rate base based on the fact that the road was not owned by Hydro.

Based on our discussions with the Company regarding the project, there was no capital costs included in rate base. In 2012 the Company incurred $600,000 in operating costs related to the project.

Board Order P.U.5 (2012)

In P.U. 5 (2012), the Board approved the $2,641,200 capital expenditures required to do the necessary work to Refurbish the Fuel Storage Facility at the Holyrood Thermal Generating Station. The Board requested that Hydro file a report with the Board by March 1, 2013, justifying the scope of the work and the level of expenditure. This report is required to demonstrate that only work that was necessary to maintain Tank 3 as long as it will be required was carried out. Pursuant to this requirement, Hydro filed a report to the Board regarding this project in February, 2013.

In P.U. 5 (2012), the Board approved the $1,474,300 (2013 – $1,413,900) included in 2012 capital expenditures relating to the project to Replace Fuel Oil Heat Tracing system at the Holyrood Thermal Generating Station. The Board has ordered that the recovery of associated costs will not be allowed at this time. The Board required Hydro to separate and record these costs in an account, the disposition of which will be considered by the Board should Hydro make subsequent application for recovery of some or all of the associated costs. Costs of $783,000 were incurred in 2012 and have been appropriately deducted in Hydro's calculation of the 2012 rate base.

Capital Expenditure Reports

Confirmation was received from the Board that the Company filed quarterly Capital Expenditure reports for the 2012 calendar year.

Based upon our analysis, the following exceptions were noted with respect to Hydro's reporting requirements:

- **it did not comply with guideline 1900.6 in relation to filing a report with the Board for its intent to proceed with an expenditure greater than $50,000 without the approval of the Board using the Allowance for unforeseen Items account. Approval of these expenditures is outstanding at June 30, 2013.**
- **It remains uncertain whether the work relating to the 'Black Tickle Diesel Fire Restoration Project' was appropriate use of the 'Allowance for Unforeseen Events' account.**

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